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Volume IV
September 1981

The Magnitude and Regional Distribution of Needs for Hydropower — Phase II Future Electric Power Supply and Demand

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THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEEDS FOR HYDROPOWER

THE NATIONAL HYDROPOWER STUDY

Phase II - Future Electric Power Supply and Demand

VOLUME IV

Institute for Water Resources
U.S. Army Corps of Engineers
Fort Belvoir, Virginia

September 1981

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FOREWORD

Authorization

Authorization to perform this study was granted by the U.S. Army Corps of Engineers (COE) Institute for Water Resources (IWR), in a letter to Harza Engineering Company (Harza) dated 21 September 1978. The work is being performed under Contract Number DACW72-78-C-0013, regarding "The Magnitude and Regional Distribution of Needs for Hydropower, The National Hydropower Study."

Objective

The objective of this report is to present information on the magnitude and distribution of electric capacity and energy requirements for the United States, in order to determine the most likely potential for the utilization of new hydropower resources. This report constitutes the Phase II report (Volume IV) of the study. The Phase I report (Volume III) provides an overview of the status of the 1978 electrical power system and electrical demand and supply in the United States. The Phase II report projects demand and supply conditions through the year 2000.

Scope of Work

The overall study area is the electrical power system in the United States. An analysis is made of the future electric capacity and energy demands in each study region to identify future additions of generation capacity (especially hydropower) to the existing power supply system. The study regions are selected in accordance with the following guidelines:

(a) the maximum size of a study region is the area represented by one of the nine National Electric Reliability Councils (NERC) within the contiguous United States. The States of Alaska and Hawaii each are treated as separate study regions.

(b) smaller sub-regions within those of "a" above may be defined by power pools or coordinating groups.

The data used in the study are published and readily available information. Data on projections of electric power system loads and capabilities have been obtained from Federal and state agencies, private institutions, regional coordinating councils, and individual

utilities. Projections are made for the years 1985, 1990, 1995, and 2000.

Utility forecasts of demand and supply, economic conditions, and government regulations are in a constant state of flux. Consequently, the data gathered for this study can quickly become outdated and the forecasts developed must be periodically updated. The results presented in this volume must be viewed with this in mind.

Content of the Report

The report consists of a national summary followed by twelve chapters and three Appendices with supporting tables and exhibits. Prior to Chapter I, an overview of the electric system forecast for the entire nation is presented. Chapter I contains a description of the methodology used in the study. Each of the following nine chapters (Chapter II through X) of this report provides information on the magnitude and distribution of electric capacity and energy requirements for one of the nine specific NERC regions and the individual study sub-regions within the region. Chapters XI and XII provide information on the magnitude and distribution of electric capacity and energy requirements in the State of Alaska and the State of Hawaii.

The appendices are as follows:

Appendix A - Load Curves Analysis for Estimating Power and Energy Requirements for Hydroelectric Plants.

Appendix B - Attractiveness of Hydropower.

Appendix C - Sensitivity of Projections.

Harza Participants

Harza personnel who have participated in this study include:

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H.H. Chen	Assistant Head, Water and Energy, Planning and Design Department
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P. Hartel	Hydroelectric Planning Engineer

NATIONAL SUMMARY
FUTURE ELECTRIC POWER SUPPLY AND DEMAND

Introduction

Electric energy is one of the most convenient, efficient, and important forms of energy available in the Nation. The very future of our country depends to a large extent on our ability to adequately supply the demand for this product. In subsequent chapters of this volume, a forecast of the expected regional demand for electric power and energy through the end of this century is presented as well as an estimate of the generation sources that will be available to meet these demands.

A brief summary of the methodology used in developing the electricity projections contained in this volume and a national summary of these results is presented in the following sections of this summary. An overview of the national and regional electrical situation for 1978, with emphasis on the existing role of hydropower, is discussed in Volume III.

The electric utility power system in the contiguous United States is made up of the following nine Regional Electric Reliability Councils:

ECAR	East Central Area Reliability Coordination Agreement
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interpool Network
MARCA	Mid-Continent Area Reliability Coordination Agreement
NPCC	Northeast Power Coordination Council
SERC	Southeastern Electric Reliability Council
SWPP	Southwest Power Pool
ERCOT	Electric Reliability Council of Texas
WSCC	Western Systems Coordinating Council

These nine regional groups of power suppliers, whose boundaries are shown on Exhibit I-1, form the National Electric Reliability Council (NERC). NERC was formed voluntarily by the electric utility industry in 1968, and incorporated in 1975. Its purpose is to augment the reliability and adequacy of bulk power supply of the electric utility systems in North America. Although regional council memberships also comprise the Canadian systems in the provinces of Ontario, British Columbia, Manitoba, and New Brunswick, the Canadian electric utility systems are not included in this report. In addition to the nine NERC regions, separate studies are also made for the States of Hawaii and Alaska.

In this volume, electricity projections are made for each of the nine regional councils plus Alaska and Hawaii. Projections are also made for smaller geographical areas or sub-regions in five of the nine NERC regions. These five NERC regions are represented by as few as two or as many as six sub-regions.

A detailed description of the methodology used to develop the forecasts contained in this volume is presented in Chapter I. Individual regional and sub-regional electricity forecasts are contained in Chapters II through XII. In order to more fully understand the projections and their relationship to hydroelectric power generation, the reader is referred to Appendices A, B, and C.

Future Demographic and Economic Growth

Forecasts of regional demographic and economic growth are taken from the OBERS[1/] Series E projection [1][2/]. Series E refer to the latest detailed regional and national projection of population, employment, and earnings up to the year 2000. In this report, as in Volume III, the OBERS areas for which projection data are utilized, are the functional economic areas delineated by the Bureau of Economic Analysis (BEA). Each region and sub-region is approximated by specific BEA economic areas. The demographic and economic OBERS projections are aggregated by the representative BEA areas to arrive at regional and sub-regional totals. Table 1 summarizes the significant demographic and economic projections for the United States.

Future Electric Power Demand

To define a reasonable range of future electricity demands which reflect different assumptions such as population and economic growth rates, impact of various conservation programs, load management, and energy pricing policies, three electricity projections (Projections I, II, and III) are developed from published and readily available information and data on electricity demand forecasts.

1/ OBERS is an acronym signifying a unified effort of the former Office of Business Economics (OBE), Department of Commerce, and the Economic Research Service (ERS), Department of Agriculture. In 1972, the OBE was renamed the Bureau of Economic Analysis (BEA), and will be so referred to in this report.

2/ Numbers in brackets refer to references which immediately follow Chapter XII.

Table 1

UNITED STATES
PROJECTED POPULATION, INCOME, AND MAJOR SECTOR EARNINGS
(Income and Earnings are in constant 1967 dollars)

	YEARS			
	1980	1985	1990	2000
Population (million)	223.5	234.5	246.0	263.8
Total Personal Income (Billion $)	1,068	1,273	1,517	2,154
Per Capita Income ($)	4,780	5,430	6,170	8,165
Total Earnings (Billion $)	837	993	1,177	1,657
Sector Earnings (Billion $)				
Agriculture	21.3	22.1	23.0	25.9
Mining	6.5	6.9	7.3	8.4
Construction	51.9	60.9	71.3	97.6
Manufacturing	219.5	253.0	291.6	388.5
Transportation, Communications, and Public Utilities	58.7	69.0	81.2	113.0
Wholesale and Retail Trade	133.9	154.9	179.1	243.4
Finance, Insurance, and Real Estate	48.5	59.2	72.4	106.9
Services	150.3	187.7	234.6	359.8
Government	147.0	178.3	216.1	313.9

Projection I is derived from the utilities. It was chosen to reflect the plans of the electric industry. Each NERC region is required to forecast annually electric demand and supply for the next ten years, and provide "conceptual planning" projection for the subsequent eleven to twenty years. The reports filed by the utilities through NERC to the Department of Energy on April 1, 1979 [3] were the latest available for this study. Projections for Hawaii are based on the projections made by Hawaiian Electric Company and its subsidiaries [35]. The projections for Alaska are based the on projections made by the Federal Power Commission (now FERC) [33].

Projection II is derived from forecast made by the Institute for Energy Analysis (IEA) at the Oak Ridge Associated Universities in September 1976 [4]. The IEA study is a well recognized independent study of the Nation's future energy demand. The IEA forecast reflects a low growth rate for both the nation's future energy demands and the Gross National Product (GNP). It was chosen to represent the expected lower range of the electric energy forecasts. The forecasts assumes a large, nationwide move to energy conservation. From this study, the annual per capita electric energy consumption growth rate in the United States is projected to be 2.6% for the period 1978-2000.

Projection III is based on the "Consensus Forecast of U.S. Electricity Demand" [5]. The electricity demand in the "Consensus Forecast" was derived from the energy demand which represents an average of 15 forecasts made by private and Federal economists in the post-embargo period. They are conservation oriented, and not the historical growth forecast that usually were made in the pre-embargo period. The Consensus Forecast is chosen for use in this study because it represents an average, or "middle ground" forecast of electric energy. Based on this study, the annual per capita electric energy consumption growth rate is expected to decrease from 4.5% between 1978 to 1985 to 3.2% between 1995 and 2000.

Projections II and III are based on per capita electric energy growth rates. The 1978 per capita consumption for each region, and sub-region is used as the base condition. To compute the per capita energy consumption, the OBERS population forecasts are adjusted to reflect the latest (1978) population estimates published by the Department of Commerce [2]. The revised population growth rates provide more realistic near future trends in population (Exhibit I-3) than the estimates based on the original OBERS forecast.

From projections I, II, and III, a "median" electricity projection is selected and is considered to be representative of future regional (or sub-regional) demands. A summary of the inational projections are shown on Exhibit I-4. As indicated in this exhibit, the annual "median" electric energy demand of the United States is expected to increase from 2,210,000 GWh in 1978 to 5,550,000 GWh in 2000, representing an average annual growth rate of 4.3%. The peak demand is expected to grow from 397,000 MW in 1978 to 1,029,000 MW in 2000, representing an average annual growth rate of 4.4%.

Estimate of Electric Power Supply

A regional appraisal is made of major fuel resources for power generation, namely coal, oil, natural gas, and uranium. In addition,

other exotic energy sources are considered. These other energy sources include, among others, shale oil, tar sands, geothermal, tidal, wind, wave power, and solar. Descriptions of these fuel resources are presented regionally, and are based on references from other studies involving energy sources and conversions.

In this study, an estimate of potential hydropower resources in the United States at both existing dams and undeveloped sites is presented. The hydroelectric power potential at existing dams is based on data contained in a 1977 Corps of Engineers report [6]. The hydroelectric power potential at undeveloped sites is based on data reported in 1976 by the Federal Power Commission [7]. More definitive information on hydropower potential is contained in the Regional Reports. Table 2 shows the relationship between total hydroelectric power potential, existing hydroelectric power capacity, and the total installed electric generating capacity as of January 1979 for each NERC region, Alaska, and Hawaii.

Transmission and marketing aspects of future hydropower projects are not parts of this report. These items are discussed in another volume of the National Hydropower Study.

Load Resource Analysis

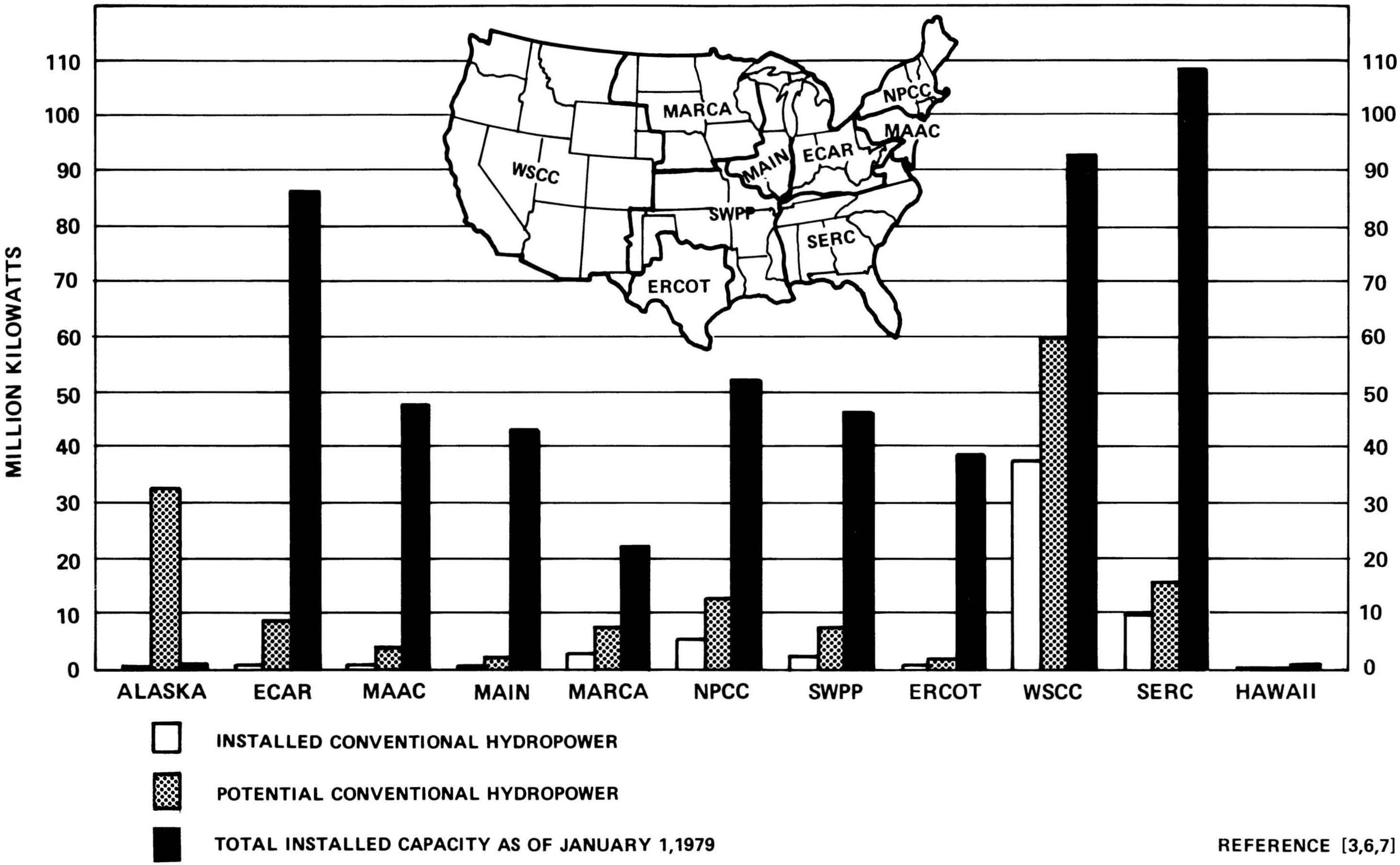
In this report, it is assumed that the best estimates of reserve margin, which is the amount by which projected operable resources exceed projected demand, are provided by the utilities themselves. However, to provide an acceptable level of reliability in meeting the "median" load demand in most regions of the country, a minimum reserve margin of 17% and a maximum of 25% are assumed. Reserves in excess of 25% of the median demand are made for some areas, such as, Alaska, where there are very few interconnections.

Each NERC region except for ERCOT has active interconnections between its electric systems and other reliability councils. Table 3 summarizes the emergency transfer capabilities between neighboring NERC regions projected for 1988 [18].

Future generation plans up to the year 2000 are presented for each NERC region and sub-region, Alaska, and Hawaii. The total generation resources to serve the median demand for 1985, 1990, 1995, and 2000 are estimated using the utility reserve margin percentages, as discussed previously, and the median peak demand. As a starting point in defining the future generation mix, it seems reasonable to follow the short-term plans of the utilities and to modify their long-term plans considering the following main factors:

TABLE 2

GENERATING CAPABILITY AND POTENTIAL HYDROPOWER BY REGIONAL ELECTRIC RELIABILTY COUNCILS, ALASKA, AND HAWAII



REFERENCE [3,6,7]

Table 3

CONTIGUOUS UNITED STATES
EMERGENCY INTER-REGIONAL POWER TRANSFER CAPABILITY
(1988 - MW)

From	To ECAR
MAAC	2,600
MAIN	2,800
SERC	
TVA	5,000
VACAR	5,500
NPCC	2,000

From	To MAAC
ECAR	5,200
NPCC	4,400
SERC	4,550

From	To MAIN
ECAR	4,000
SWPP	1,600
MARCA	600
SERC	3,500

From	To MARCA
MAIN	2,300
SWPP	1,000
WSCC	100

From	To NPCC
ECAR	3,100
MAAC	2,450

From	To SWPP
MAIN	600
MARCA	1,000
SERC	1,700

From	To SERC
ECAR	3,600 (VACAR)
ECAR	4,000 (TVA)
MAAC	3,750
MAIN	3,100
SWPP	2,000

From	To ERCOT
No operating interconnections	

From	To WSCC
MARCA	100

- The current indications of utilities philosophies.

- Anticipated Federal and state energy policies and regulations.

- The characteristics of electric loads.

- Relative capital and energy costs of different types of generation.

- Differential escalation in fuel prices.

- Other specific regional factors such as hydropower potential and availability of other fuels.

To reflect the uncertainties and the numerous factors which affect future generation mixes, a range of future installed capacities for each major generation type is developed. Table 4 summarizes the most probable generation mix to meet the "median" demand in each region for the year 2000. For future hydropower capacity, the range reflects the difference between the "committed" hydropower projected by the utilities and the total potential that could be developed. In addition, in each regional chapter, the specific role of existing and planned conventional hydropower and pumped storage is discussed.

Sensitivity Analysis

The projections of future electric demand and supply presented in this chapter are based on numerous factors, each of which is sensitive to public opinion, economics of energy use, and changes in domestic or international policies. The number of variations that could be analyzed is nearly infinite. However, regardless of variations in items, population reflects the ultimate energy use. Of particular importance are variations in projected population growth rates. Such variations will directly affect Projections II and III, since they are based upon per capita energy consumption. Projection I would be indirectly affected as it is based on an aggregation of utility forecasts, each of which may have a different underlying forecast methodolgy. Changes in projected economic growth, rate of implementation of conservation measures, Federal and state regulations, and other regional factors are difficult to gauge but will no doubt affect all of the projections. A general discussion of projection sensitivity is presented in Appendix C.

Changes in the regional population growth rates would definitely affect Projections II and III, and, most likely, the "median" Projection. The following table indicates what effects, if any, selected

changes in population growth rates would have on the median projection of electric energy consumption in the entire United States.

Percent Change in Population Growth Rates	Percent Change in Energy Demand of Projections II & III in the Year 2000	"New" Median Enegy Demand (GWh) 1/
-50	-9.0	5228.2
-15	-2.8	5470.1
0	0	5550.9
+15	+2.9	5641.0
+50	+10.0	5835.6

1/ Median energy demand is computed as the median of Projection I (unchanged) an Projections II and III (adjusted as indicated).

Throughout the country, electric energy conservation measures and load-management measures will most likely be employed in an attempt to offset rising energy prices regardless of other economic activity. Large scale adoption of conservation will have an effect on electric generation requirements similar to that of depressed economic conditions in that projected demand for both electric power and energy would be reduced. However, conservation will not impede hydroelectric generation, but rather will point to its value and its contribution to conservation. More likely than not, planned thermal-electric generation will be curtailed.

Conversely, if economic activity were to exceed expectations, future demand for energy might exceed the median projection. However, conservation and load-control measures could relieve the capacity situation somewhat, so that electric energy use would increase to a larger degree than would capacity requirement. Under such circumstance, hydroelectric power and energy would provide operating economy and there would be demand for all that could be economically installed.

To summarize, electric capacity and energy demand could vary widely from the projections, but the overall need for national energy conservation will continue to justify the production of hydroelectric energy.

Table 4

GENERATION MIX
YEAR 2000

Generation Type	ECAR %	MAAC %	MAIN %	MARCA %	NPCC %	SERC %	SWPP %	ERCOT %	WSCC %	ALASKA %	HAWAII %
Base											
Nuclear	15-18	20-25	22-25	14-18	26-30	22-26	12-15	12-16	15-18	-	-
Coal	50-53	38-40	40-42	44-48	22-25	38-42	36-40	35-40	30-33	20-25	-
Oil	-	2-5	-	-	10-14	1-3	-	-	5-7	5-8	50-55
Gas	-	-	-	-	-	-	10-12	20-25	-	15-18	-
Conv. Hydro	-	-	-	1-2	0-1	0-1	-	-	10-12	20-30	-
Geothermal	-	-	-	-	-	-	-	-	1-3	-	0-5
Intermediate											
Coal	22-24	10-15	25-28	18-20	5-8	15-18	13-15	-	8-10	3-5	-
Oil	1-2	8-10	1-2	0-1	8-10	4-6	2-4	-	3-5	3-5	20-22
Gas	-	-	-	-	-	-	6-9	14-17	0-1	4-6	0-2
Conv. Hydro	0-1	0-1	0-1	2-3	2-5	1-3	1-2	-	4-6	5-10	0-1
Geothermal	-	-	-	-	-	-	-	-	0-2	-	0-5
Bagasse	-	-	-	-	-	-	-	-	-	-	2-5
Other	1-2	1-2	1-2	1-2	1-2	1-2	1-2	1-2	1-3	1-2	1-2
Peaking											
Coal 1/	-	-	-	-	-	-	-	-	-	-	-
Oil	2-4	8-10	4-6	10-13	8-9	3-5	2-3	0-1	3-5	1-3	12-15
Gas	0-1	-	0-1	-	-	-	4-8	12-15	1-3	2-4	-
Conv. Hydro	0-1	1-2	0-1	3-5	3-5	2-4	1-2	0-1	3-6	5-10	-
Pumped Storage	2-5	1-3	2-6	0-4	4-6	2-4	0-3	0-1	2-5	-	-
Bagasse	-	-	-	-	-	-	-	-	-	-	2-5
Other	1-2	1-2	1-2	1-2	1-2	1-2	1-2	1-2	1-3	1-2	1-2
Total Capability (GW)	204.3	79.0	100.0	54.4	95.2	280.1	118.3	96.2	241.1	2.6	3.3

1/ All coal-fired plants are classified as either base on intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Chapter I

METHODOLOGY

Introduction

This chapter discusses the methodology used in developing the national and regional projections contained in this report. Included are projections of the following items to the year 2000:

(1) Population (and selected economic indicators)

(2) Electric power demand and supply

(3) The relative amounts of alternative sources of electric generation (generation mix).

Separate projections are made for each of the nine National Electric Reliability Council (NERC) regions, and the States of Alaska and Hawaii. In addition, projections are also developed for the various sub regions within the NERC regions. These NERC regions and sub regions are shown on Exhibit I-1.

Projection of Population and Selected Economic Indicators

Forecasts of regional, and sub regional, demographic and economic conditions are taken from the OBERS[1/] Series E projections [I-1].[2/] Series E refers to the latest detailed regional and national projections of population and employment up to year 2000. In this report, the 1972 OBERS Series E forecast, is referred to as "OBERS."

The OBERS areas for which population data are utilized in this study are the functional economic areas delineated by the Bureau of

1/ OBERS is an acronym signifying a unified effort of the former Office of Business Economics (OBE), Department of Commerce, and the Economic Research Service (ERS), Department of Agriculture. In 1972, the OBE was renamed the Bureau of Economic Analysis (BEA), and will be so referred to in this report.

2/ Numbers in brackets refer to references which immediately follow Chapter XII.

Economic Analysis (BEA). These areas are referred to as BEA economic areas. Aggregations of BEA economic areas that approximate the NERC regions and subregions are listed on Exhibit I-2. It should be noted that in most cases the approximation is very close to the actual delineation of a region or subregion. For some areas, this approximation does not reflect the actual delineation of a region or sub region. However, the future trends derived from the BEA areas can be considered as reasonably reliable, and consistent for the purpose of a national study. Consideration has been given to use the Water Resources Subareas rather than BEA areas. However, for most regions and subregions, a better approximation of regional boundaries is obtained using the BEA economic areas. In some regions (or subregions) there may be as much as a 5 percent difference between actual and BEA derived population. However, the overall results and forecast developed in this study would not be affected as much because they are dependent upon rate of population increase.

BEA areas are defined along county boundaries and have the functional characteristic that the area contains both its labor market and labor supply. Thus, each BEA area is delineated such that it contains the place of work and place of residence of most of its labor force, with a minimum of commuting across economic area boundaries. In this study an attempt is made to approximate the geographic extent of NERC regions and subregions by BEA areas. The projected population data for the BEA areas which represent a region (or subregions) are aggregated to develop the regional population projections. The OBERS study also includes estimates of economic sector earnings, total regional earnings, personal income, and per capita income. The OBERS study provides a consistent set of demographic and economic projections that assume that future regional development will, in general, follow historical trends.

Projections of Electric Power Demand

The projections used in this report are analyzed in a simplified manner for practicability. It is known that many factors such as income, population changes, age distribution, unemployment rates, leisure time, and climate affect use of electricity. Studies endeavoring to develop and use such data involve complexity beyond the scope of this Volume. The projections, described below, underlying this study consider the individual factors. Major factors of significance for further analysis are population, per capita usage, and load factor, all of which are used in this Volume.

To provide a range of forecasts, three projections (Projections I, II, and III) are developed from published and readily available infor-

mation and data on electric power demand forecasts. The three projections are intended to define a reasonable range of future demands. This range is defined from the high and low projections which reflect different assumptions concerning (1) population and economic growth rates and (2) the impact of various conservation, load management, legislative, regulatory and energy pricing policies. From these three projections, a "median" projection is selected and is considered to be representative of future power and energy demand of a region or subregions. The procedure used to derive the median projection is described at the end of this section.

Two of the projections are based on per capita electric-energy consumption. To compute the per capita electric-energy consumption, the OBERS Series E population forecasts have been adjusted when necessary to reflect the 1978 estimates of state populations as published by the Department of Commerce [2]. The populations of the state or states which best approximate each NERC region and subregions are aggregated for 1970 and 1978. The population growth rates for the 1970-78 period are then computed. These revised population growth rates provide more realistic near future trends in population (Exhibit I-3) than the estimates based on the original OBERS 1970-1980 forecast.

The 1970 OBERS populations, aggregated by BEA areas to approximate the NERC regions and subregions serve as the base for adjusted population forecasts. The 1978 population is computed from this base using the revised 1970-1978 annual growth rate(s) computed above. The 1985 population is computed from the 1978 population using an average growth rate. The rate between 1978 and 1985 is derived as the average of: a) the revised 1970-1978 annual growth rate and b) the 1980-1985 annual growth rate from the original OBERS population forecast. The 1990, 1995, and 2000 population estimates are based on the original OBERS average annual growth rates for the periods following 1985. In some areas, such as the Northeast, the growth rates may be large if compared to more recent Census Bureau population forecast studies. In others areas, they may be small. The time lag between this study and publication of data results in some discrepancy between projections in this report and more recent data. Overall, however, it is believed that the results are reasonably representative for the assessment of a rapidly changing situation.

The projections upon which the load growth forecasts are based have great diversity in method and underlying assumptions leading to a corresponding diversity in results. Forecasting the future accurately is difficult, of course, and is dependent, in part, on the assumptions

relating causes and effects. As events governing energy prices and energy use have amply demonstrated in the last few years, unpredictable events often nullify assumptions underlying the projection and so cause the projection to vary from the results actually obtained. The forecasts in this report are subject to the same factors.

Fuel price is also a factor in use of electric energy, especially in regions where oil forms a large part of the generation. Recent oil price increases, the increasingly unstable situation in the oil producing countries, and the effect that these conditions have already had and will continue to have on economic growth and energy are difficult to gauge. At this time, there is no clear relationship between fuel price and per capita consumption. However, an attempt has been made to account for such factors by the use of Projection II which reflect a low growth rate due, in part, to the effect of higher fuel prices.

The following section discusses the methodology involved in making Projections I, II, and III, and deriving the "median" forecast of electric demand.

Projection I

Projection I is derived from forecasts made by the utilities. It was chosen to reflect what the electric industry plans. The methodology used by utilities to forecast future demands varies greatly from a general extrapolation of historical trends to detailed econometric models by consumer categories. A summary of different types of forecast methodologies is presented in Reference 38.

Based on utility projections, each NERC region is required to forecast annually electric demand for the next ten years and provide "conceptual planning" projections for the subsequent eleven to twenty years. The reports filed by the utilities through the Regional Electric Reliability Councils to the Department of Energy on April 1, 1979 [3] were the latest available for this study. In these reports the utilities forecast energy demand and peak demand for the 1979-1988 period. The "conceptual planning" projections for the 1989-1998 period include peak load but not energy.

Projection I peak demands for years 1985, 1990, and 1995 are those made by the utilities in the reliabiity council reports. The peak demand in the year 2000 is extrapolated from these data assuming continuation of the 1995-1998 peak demand average growth rate. The 1985 energy demand is also forecast by the utilities and beyond 1985,

energy forecasts are calculated from the peak demands using the assumed load factors discussed below.

The annual load factor for 1985 is computed using the annual energy and peak demand projected by the utilities. The 1990 through 2000 annual load factors are assumed to be equal to the average of the 1985-1988 annual load factors computed from the utility forecasts. The assumption is based on the fact that, in most cases, the utility load factor forecasts for the next decade change only slightly. Opposing forces are at work relative to future load factors. Various load management programs, incremental rate schedules, slower rate of growth of peak loads, and some other factors could increase the load factor. However, the tendency for increase in load factor could be offset to some degree by the utilization of such sources of energy as solar, wind, geothermal, or cogeneration at the customer site. These sources are expected to reduce the energy demand on electric utilities, and decrease the load factor because they will not reduce the peak demand appreciably. At this time, there is no basis for saying that forces tending to change load factor in one direction are greater than those tending to change it in the opposite direction.

Consideration also was given to relating load factors to OBERS projections, but OBERS data are presented in terms of population projections and annual values of various economic activities. Each of the activities is the aggregate of a number of sub-activities. The activities use sources of energy, of which electricity is only one. The inter-relationship between the various activities and the lack of detail as to energy source do not permit the direct evaluation of electrical load factor from OBERS data.

Analyzing the electricity projections made by the utilities during the past decade, a clear downward trend in their forecast is evident. The more recent utility forecast appear to reflect the changes in economic and demographic growth as well as other parameters such as implementation of more energy efficient technologies and conservation measures. As an example, Table I-1 compares the 1985 and 1995 peak demand projections for each NERC region as reported in the 1976 and 1979 reports. Except for the MARCA region, all 1985 projections have been reduced between 10 and 20%. The projections for the 1995 peak demand show a greater difference, with 20 to 36% reduction. This reduction agrees with the effect of conservation described in Appendix C.

Table I-1

PEAK DEMAND PROJECTIONS - MW -

NERC Region	1985 1976 Report	1985 1979 Report	1985 Change %	1995 1976 Report	1995 1979 Report	1995 Change %
ECAR	100,774	80,165	-20.4	216,300	137,900	-36.2
ERCOT	46,203	40,712	-11.9	82,419	65,827	-20.1
MAAC	50,150	40,426	-19.4	78,490	52,016	-32.1
MAIN	56,539	46,636	-17.5	102,400	71,644	-30.0
MARCA	30,501	29,182	-4.3	48,460	47,776	-0.1
NPCC	51,662	44,852	-13.2	81,535	59,720	-26.7
SERC	144,737	121,920	-15.8	259,617	195,802	-24.6
SWPP	69,165	58,966	-14.7	141,827	102,701	-27.6
WSCC	110,051	98,364	-12.5	181,000	142,957	-21.0
TOTAL	659,782	561,223	-14.9	1,192.048	876,343	-26.5

At the time of the report preparation, the 1980 NERC report was not available. However, comments from NERC indicate that the 1980 projections reflect further reduction in future power and energy demand. For example, the peak demand projection for the year 1987 in the 1979 NERC forecast (approximately 610,000 MW) is now expected to occur in 1989 instead.

Per capita energy consumption for each region and subregion is estimated using utility total energy forecasts and the adjusted OBERS population projections. As pointed out in the previous section, the population estimates of some of the regions (and/or subregions) may be in error because of the relative size of the BEA area(s) which are selected to represent a region (and/or subregion). However, even though this could cause the per capita consumption data to be in error, its effect on the magnitude of the power and energy forecast would be minimal.

Projection II

Projection II is derived from the forecast made by the Institute for Energy Analysis (IEA) at the Oak Ridge Associated Universities in September 1976 [4]. The IEA study is a well-recognized independent

study and was chosen because it reflects a low growth rate of the nation's future energy demands. The IEA study projects many parameters such as: economic and demographic growth, labor force and productivity, total energy demand and electricity demand. The main finding of the IEA study is that both GNP and energy demand are likely to grow significantly more slowly than has been assumed in most analysis of energy policy. Two scenarios designated "high" and "low" of electricity demand were developed in this study for the United States to the year 2010. However, even the "high" scenario is much lower than most previous estimates. The energy conservation measures considered in developing the IEA projections are summarized below:

A. <u>Energy-Saving Technologies</u>

Four specific technologies not now uniformly or widely used but which are among the lists of currently available and potential energy-saving technologies appropriate for various services and processes in the U.S. economy have been singled out by the IEA. If these four technologies are increasingly adopted during the next 35 years under price or supply pressures, tax differentials, or government intervention, they would have the largest impact on energy and/or dollar savings. These four technologies are as follows:

(1) New building construction of improved energy-conserving design, using heat pump systems and a heat storage tank for heating and cooling.

(2) Smaller and lighter-weight automobiles and service trucks with more efficient engines and transmissions, and involving less steel and aluminum.

(3) Improved industrial boiler design and heat recovery processes in the various energy-intensive manufacturing industries with fuel shifted from oil and gas to the direct use of coal and nuclear heat or to electricity.

(4) Electric load-level switching for the small consumer of electricity as well as for the large consumer. Although this would not save energy, it would reduce peak loads and save the high cost of peaking power.

The introduction of the major technologies suggested here can be timed to coincide with the normal retirement of capital items when the technologies are cost effective in each case. The use of these

energy-saving technologies with the others listed below would reduce the total U.S. energy requirements and would shift the fuel demands from oil and gas to electricity and the direct industrial use of coal, nuclear, or solar heat. Each technical strategy suggested is associated with energy-use categories in a particular sector. These are discussed more fully as each sector demand is examined.

B. Major Energy-Saving Technical Strategies

1. Improved household and commercial heating, cooling, hot water, lighting and appliances.

   a. Construct new buildings with better design and insulation standards and with electric heat pump systems and a heat storage tank. Cut average heat losses by 30% and fuel requirements by 50% on all new construction. Retrofit existing buildings to cut fuel requirements by an average of 69% on retrofits. Shift oil and gas-fired systems to be retired to electric heat pump systems.

   b. Improve water heater insulation and eliminate severe pipe losses. Improve large appliance efficiencies. Fuel requirements decrease by 5% by 1985, 8% by 2000, and 10% by 2010 for hot water, cooking, refrigeration, and clothes drying.

   c. Improve household and commercial electric lighting and small electric appliance efficiencies by 5% by 1985, 8% by 2000, and 10% by 2010.

2. Industrial process steam and heat, and electric drive.

   a. Improve industrial boiler design and heat recovery processes, cutting fuel consumption by 15% by 1985, 25% by 2000, and 30% by 2010. Shift industrial boilers for low-temperature heat and steam from oil and gas to the direct use of coal and nuclear heat or to electricity, possibly with support from solar energy.

   b. Improve iron/steel processes and aluminum processes to decrease average energy use per ton by 5% by 1985, 10% by 2000, and 12% by 2010.

c. Improve industrial electrical lighting efficiencies by 10% by 1985, 17% by 2000, and 20% by 2010.

3. Electricity generation and distribution.

a. Decrease expensive electricity generation peak load requirements by implementing load-leveling technologies for the small consumer as well as the large one. This would include heat storage and heat pump systems in the household, commercial, and industrial sectors, and automatic loadlevel switching for hot water and large appliances in the household and commercial sectors.

b. Use cogeneration of electricity and process steam and heat where economical. Encourage solar, geothermal, waste, and wind energy systems in those geographic areas where such systems are plausible.

C. Conclusions

From a reference case that does not include efficiency improvements and no real price increase, two scenarios related to a predicted level of economic activity, called the "Reference Base Case", were developed by IEA, and are summarized in Table I-2.

Table I-2

ELECTRIC ENERGY & DEMAND ASSUMPTIONS FOR THE YEAR 2010
(quads or 10^{15} Btu)

	Reference Base Case Electricity	High Scenario Elect.	High Scenario % of Ref. Case	Low Scenario Elect.	Low Scenario % of Ref. Cas
Transportation	0.5	0.5	100	0.5	100
Residential	31.6	26.0	82	16.9	79
Commercial	21.3	17.4	82	10.3	48
Industrial	44.0	28.5	65	27.8	63
Total	97.4	72.4	74	55.5	57

Table I-2, which presents data for the year 2010, is shown to indicate the diversity between projections. Such detailed data were not

readily available for the year 2000. Nevertheless, sufficient data are furnished to permit load growth estimates for intermediate years. From these scenarios, and from the IEA population projections, the annual per capita electric energy consumption growth rate in the United States is projected to be 3.8% in the "high" scenario, and 2.6% in the "low" scenario, for the period 1985-2000. The "low" scenario is chosen in this study to represent Projection II.

The low growth rate reflects the lower economic growth anticipated by IEA over this period which is predicted upon the following factors: (1) a low fertility rate (1.7 birth per woman), (2) a slower rise in labor force, (3) a rate of 2.0% of average annual growth of labor productivity, (4) a 2.7% annual growth rate in GNP, (5) higher efficiencies and improvement factors in generators, motors, appliances, transmission, etc., (6) accelerated implementation of conservation measures, and energy saving technologies, and (7) the effect of higher energy prices (the average electric energy price being twice the price in the reference base case).

Although the growth percentage rate may vary from one area of the country to another, data on a regional basis are not readily derivable from the IEA study. In Projection II, the annual per capita electric energy consumption growth rate is assumed to be 2.6% for all subregions of the United States for the entire period 1978-2000.

For each region and/or subregion, the 1978 per capita energy consumption data is the base condition. Future energy demand is computed from the base using the assumed 2.6% growth rate in per capita consumption and the adjusted OBERS population projections. The peak demand is computed from the energy using the utility load factors derived in Projection I.

Projection III

Projection III is based on the "Consensus Forecast of U.S. Electricity Demand" [5]. The electricity demand in the "Consensus Forecast" was derived from the energy demand which represents an average forecast by Federal and private economists in the post-embargo period, as listed in Table I-3. The forecasts in Table I-3 are conservation-oriented forecasts and are unlike forecasts based on the historical growth that usually were made in the pre-embargo period.

The group of forecasts listed in Table I-3 assumes that a determined national effort to reduce demand for energy through application

Table I-3

LIST OF FORECASTERS

Forecaster	Date of Forecast
1. NASA/ASEE TERRASTAR	September 1973
2. Environmental Protection Agency	November 1973
3. U.S. Atomic Energy Commission (D.L. Ray)	December 1973
4. Ford Foundation technical fix	Early 1974
5. Ford Foundation (zero energy growth)	Early 1974
6. U.S. Atomic Energy Commission (Office of Planning and Analysis)	February 1974
7. L.T. Blank and R.I. Riley	March 1974
8. Council on Environmental Quality	March 1974
9. MIT (Hudson Jorgenson)	May 1974
10. MIT (judgmental)	May 1974
11. National Academy of Engineering	May 1974
12. NASA/ASEE MEGASTAR	September 1974
13. Federal Energy Administration Project Independence	December 1974
14. ERDA (Office of Planning and Analysis)	February 1975
15. E. Teller	April 1975

of energy-saving technologies will be successful and that continued high world oil prices will keep domestic energy prices high, resulting in lower demand. Some forecasters in this group even project zero per capita energy growth rate by the year 2000. For the year 2000, the average of the conservation oriented forecasts of total U.S. energy demand (132 Quads) was approximately 15 percent lower than the average of the forecasts made during the pre-embargo period (150 Quads).

In the "Consensus Forecast", electricity demand was correlated as a function of the percentage of total energy demand for both the historical growth and the conservation oriented forecasts. The average of these results represents the "consensus" forecast and is summarized in Table I-4. The heat rate is kept at 10,800 Btu/kWh until 1985 to reflect a realistic approach. The per capita electric energy consumption is computed from the electrical generation projections and the population, obtained from the OBERS adjusted population projec-

Table I-4

CONSENSUS FORECAST

	1980	1985	1990	1995	2000
Total Energy (10^{15} Btu)	88	100	110	121	132
Utility Electricity (percent of total)	30.7	35.4	39.2	43.6	48.4
Electrical Generation (10^{15} Btu)	27.0	35.4	43.1	52.8	63.9
Heat Rate (Btu/kWh)	10,800	10,800	10,300	10,300	10,300
Electrical Generation (kWh x 10^9)	2,500	3,270	4,200	5,100	6,200
Population (10^6)	223	234	246	254	264
Per Capita Consumption (kWh/capita)	11,210	14,000	17,070	20,080	23,500
Per Capita Growth Rate (%)	4.5	4.0	3.3	3.2	

tions. The per capita consumption growth rate computed for the period 1980-1985 is used for the total period 1978-1985.

The computed growth rates, which indicate a moderate increase in electricity demand, are used in this study to compute the electric energy in Projection III after 1978. As applied to Projection II, the per capita electricity consumption growth rates are not readily available by regions or subregions. In this study, the national per capita consumption growth rates are applied equally to all regions and subregions. It is recognized that there are variations in per capita growth rates from one region to another. The lack of regional data in the Consensus report makes it difficult to adjust for such variations.

The computational procedures to calculate energy and peak demand in each projection year are the same as those described in Projection II.

"Median" Projection

Projections I, II, and III represent reasonable ranges of growth in future electricity demand. The projections incorporate the impact of various demand reducing methods. The latest utility forecasts (Projection I) clearly reflect the impact of conservation measures when compared to previous forecasts as shown in Table I-1. However, from the information available it is difficult to explicitly identify the relative importance of the various measures in each consumer category (residential, commercial, and industrial) for all regions of the country. Projections II and III also reflect the impact of conservation measures as discussed previously.

From these three projections, a "median" projection is selected and is considered to be representative of future power and energy demand of a region or subregion. For each of the selected years (1985, 1990, 1995, and 2000), the median projection is the median forecast among Projections I, II, and III. Thus, a projection which is median in one year can be supplanted by a different projection in a later year.

For any region having subregions the regional "median" energy is equal to the sum of the "median" subregional energies. The "median" energy for the United States is equal to the sum of the regional "median" energies. The regional peak is computed from the "median" energy and the load factor derived from Projection I. The per capita consumption is equal to the "median" energy divided by the population.

The projections for the United States are shown on Exhibit I-4.

Estimate of Electric Power Supplies

In this study an estimate of new hydropower resources in the United States is made based on published reports [6,7]. More detailed study of new hydropower resources is the objective of other portions of the overall National Hydropower Study, of which this report is only a part. Because the availability and cost of the other fuel resources will influence the future utilization of hydropower, an attempt is made to also appraise other resources for power generation, namely coal, oil, natural gas, and uranium [8,9,10,11,12,13]. In addition, other exotic energy sources are considered. These other energy sources include among others, shale oil, tar sands, geothermal, tidal, wind, wavepower, and solar [14,15,16,]. These other energy sources, although expected to supply only a very small percentage of the electrical

energy supply by the year 2000, are considered in developing future expansions plans for power capacity additions. A description of major fuel resources other than hydroelectric is presented regionally based on references from other studies involving energy sources and conversions.

Hydroelectric Power Potential

The potential of new hydroelectric power resources as presented in this volume includes potential at existing dams and at undeveloped sites. These estimates are based on earlier reports and are only used to provide an indication of the regional hydroelectric power potential. The data is principally used in developing the future generation mixes. More definitive information on hydropower potential is contained in the regional reports.

Existing Dams. The hydroelectric power potential at existing dams in this volume is based on data contained in a 1977 Corps of Engineers report "Estimate of National Hydroelectric Power Potential at Existing Dams", [6]. In that report, data on the capacity and electrical energy generation are available by river basins. The potential comprises hydropower installations at existing non hydropower dams, and rehabilitation of old hydropower dams. The hydropower potential in a NERC region is estimated by summing up the potential for the river basins within that NERC region. The available data do not readily permit estimates of the hydropower potential at existing dams by individual subregions.

Undeveloped Sites. In this volume, the hydroelectric power potential at undeveloped sites is based on data reported as of January 1, 1976 by the Federal Power Commission (now FERC) in the report "Hydroelectric Power Resources of the United States", [7]. In that report data on the capacity and electrical energy generation are available by states as well as by river basins. For this study, the potential for each subregion is estimated by summing up the potential of the states and portions of state within that subregion. The information on undeveloped hydroelectric sites has been taken from various river basin surveys and project investigations. The river basin studies were made by Federal agencies and various Federal-State entities operating under the aegis of Water Resources Council. Project investigations include those by Federal and State agencies and electric utilities, including studies made in connection with applications for licenses and preliminary permits. Projects with proposed installations of less than 5,000 kilowatts are generally not included in the undeveloped listings. The

undeveloped power sites in the river segments that have been precluded by law are excluded from the listings of potential hydropower.

Load Resources Analysis

Reserve Margin and System Reliability

Reserve margin is the amount by which projected operable resources exceed projected demand. Reserve margin is usually expressed as a percentage of the peak demand. In this report it is assumed that the best estimates of reserve margin for any region or subregion are provided by the utilities themselves.

When planning its system expansion an electric utility system evaluates several factors which have a significant influence on system reliability. Among these factors are the size and expected availability of existing and planned generating units, unit reliability, possible delays in service dates of new units, interconnection with other utility systems, probable availability of supplemental capacity resources, and system load characteristics, including monthly and daily load patterns. Based on this approach, most reserve margins are usually in the range of 18 to 24%. For some utilities having strong interconnections with adjacent systems and high equipment reliability, the reserve margin of the utility's own resources can be as low as 15%, although usually contracts for firm capacity in effect increase the reserve margin.

However,to provide adequate power supply to meet the "median" load projections in each region and subregion and to assume an acceptable level of reliability, a minimum of 17% and a maximum of 25% are applied to the "median" peak forecast to compute future generating capacities, except for Alaska where there are very few interconnections. Within these limits, the reserve margin is based on the utilities projections as reported in the 1979 annual reports [3]. For 1985, 1990, and 1995 the reserve margin is computed as the difference between the operable resources and the peak demand. For the year 2000, the reserve margin is assumed equal to the average of the 1995-1998 reserve margin percentage.

Interchanges of power and energy between power systems are usually taken into account when determining system reserve margins. However, it is difficult to project what imports or exports may be provided by contract in the future. Although long term (5 or 10 years) agreements are often made between neighboring utilities, they are also

quite often subject to partial withdrawal or otherwise changed during the life of the contract. Obviously short (several months or less) or even intermediate (several months to a year) power and energy transfer agreements cannot be anticipated in 1985 or beyond. For these reasons, the scheduled and nonscheduled import and export of power and energy are not considered in the load resource analysis presented in this study for the 1985 through 2000 period.

Characteristics of Electric Loads

Volume III of the National Hydro Survey report, in its description of the 1978 electric-power demand and supply, presents weekly load curves for representative utilities in each NERC region, Alaska, and Hawaii. These load curves are evaluated to estimate the characteristics of electric loads. For each representative utility, three load curves are presented, corresponding to the first week of April, August, and December 1977. These weeks are representative of seasons which govern planning and operation. Annual peak loads may occur in the summer, for which August provides good representation, or in winter, for which December provides good representation. April is representative of the off-seasons in spring and autumn, which occur between the major peak and secondary peak seasons.

The power demand or load of an electric utility is a constantly varying parameter of operation. These variations in power demand are caused by such factors as the living habits and work schedules of the people, the characteristics of the industries included in the load, and weather extremes superimposed upon more normal load patterns.

To analyze the characteristics of the weekly load curves, a procedure is hereafter described, for the purpose of this report, to define and evaluate the base, intermediate, and peak loads. This procedure is only a means to obtain some insights into the characteristics of electric loads of the representative utilities throughout the United States, and as such, should be regarded as an approach rather than a definte determination. In Volume III, the dimensionless weekly load curves are a function of the largest load in the first week of April, August, and December which may or may not be the annual peak demand. It is assumed that the weekly dimensionless load curve representative of the season in which the annual peak occurs, does not change. So as to be a function of the annual peak, the two other dimensionless curves are adjusted by the ratio of the largest load during the three representative weeks to the annual peak.

Base Load. As indicated by the weekly load curves presented in Volume III, a substantial part of the demand is on a continuous basis. This is called the "base" load. It can be defined in several ways including:

- the minimum load over a given period of time.
- the load that occurs 80 or 90% of the time.
- average of the daily minimum demands over a given period of time.

For the purpose of this report, the base load for each season is defined as the mean of the Monday-Friday minimum loads plus 10% of the computed mean minimum load. This 10% addition provides for the fact that output from base generation capacity can be cycled and that maximum efficiency occurs at less than full load. The margin between maximum efficiency and full load provides an ideal rotating reserve. During each season the base load may vary by several percent. The annual base load is the largest of the three seasonal base loads.

Peak Load. During the normal working hours of a typical weekday, the load increases to meet its peak, fluctuates during the peaking hours, and then drops off during late afternoon or early evening hours. In an electric system the range of the load considered as "on peak" is often defined as an arbitrary percentage of the annual peak load, usually about 15%. However, in this report, to reflect the differences between seasons, the peak load range is defined as the greatest difference (in the representative weekly load curve for the season) between the daily peak and the daily load equaled or exceeded 12 hours a day, Monday through Friday. The annual peak load range percentage is the largest of the three seasonal peak load range percentages. Even though typical seasonal weekly load curves are not identical from year to year, the percentage of peak load does not change appreciably.

Intermediate Load. The intermediate load range is that portion of the daily load that lies between the peak load range and the base load. It is characterized by a rapid increase in demand during the morning hours and a rapid reduction in the late afternoon or evening. During this period, the intermediate load remains almost constant and usually lasts about 12 to 14 hours each day. In this report, intermediate load for a particular season is defined as the difference between the bottom of the peak load range and the top of the base load range for the representative weekly load curve for the season.

In addition to this analysis of the weekly load curves which assume no changes in system load factors and reasonable representation of future conditions, a computer program is developed as a part of this study to produce future hourly loads in the representative weeks which reflect load factor changes. A description of this program and suggestions on how to analyze the dimensionless load-duration and load-energy tables to fit new hydropower plants into a power system is presented in Appendix A.

Generation Mix

This analysis considers that the generation plans as projected by the utilities through 1985 have a reasonable probability of execution. New plants, particularly major hydroelectric, pumped storage, nuclear, and coal-fired, cannot be ready for service until after 1985 because of the lead time required to plan, license, design, and construct such facilities. Although cancellations or deferments of scheduled generation plants could occur because of adverse financial conditions, reduced load growth, or regulatory contraints, it is considered that present implementation policies will be maintained until 1985 and that there will be no significant cancellations before 1985. If there are deferments, their effect is considered to be negligible in the long term because the deferments will represent a slowdown in new installations corresponding to a slowdown in load growth.

The total generation resources to serve the median demand for 1985, 1990, 1995, and 2000 are estimated using the utility reserve margin percentages, as discussed previously and the median peak demand. As a starting point in defining the future generation mix, it seems reasonable to follow the short term plans of the utilities and to modify their long term plans considering the following main factors:

- The current indications of utilities philosophies.
- Currently indicated Federal and state energy policy and regulations.
- The characteristics of electric loads.
- Relative capital and energy costs of different types of generation
- Differential escalation in fuel prices.
- Other specific regional factors such as hydropower potential and availability of other fuels.

For each region or subregion a generation mix for 1985, 1990, 1995, and 2000 is presented in terms of base, intermediate and peaking

capacities. These generating units, in an all-thermal system, can be defined as follows:

1. Base: Base units are those having the lowest energy cost and usually the highest efficiency. This makes them suitable primarily for continuous operation at as nearly constant load as possible. Base units usually are high-temperature, high-pressure steam turbines, which are not adaptable to rapid load change, but which can accommodate slow load changes. In general, coal-fired powerplants with heat rates less than 11,000 BTU per kWh can be considered as base. Nuclear powerplants are naturally base units. In some areas of the country oil- and gas-fired steam plants are sometimes used as base due to regional economics and availablility of fuels.

2. Intermediate: Intermediate units are those having higher energy costs and usually lower efficiency than base load units. Intermediate units have moderate ability to supply changing loads and at intervals may be shut down for short periods and then be restarted. Intermediate units may be partly obsolescent base load units, steam turbines fueled by oil, coal, or gas designed for intermediate service operating at steam temperatures and pressures lower than those used for base units, or combined-cycle units. In general, effective heat rates for intermediate operation are between 11,000 and 13,000 BTU per kWh for coal plants. Combined cycle and other oil-fired units can have lower heat rates, but because of their higher energy costs they are normally considered as intermediate units.

3. Peaking: Peaking units are those having higher energy costs than intermediate units and usually have the highest heat rates or lowest efficiency. Peaking units can respond to rapid load changes and usually are fueled by oil, although gas also can be used. Combustion turbines and diesels are used primarily for the purpose. In general, heat rates are 13,000 BTU per kWh or more.

All thermal units have the advantage of ability to produce energy continuously up to their seasonal capacity rating during any season. The ability allows intermediate and peaking units to produce base energy when occasion demands. When intermediate and peaking units are

used for base operation, their heat rates are improved above their normal operating rates. However, the cost of energy produced by intermediate or peaking units exceeds the cost of energy from base units, so that base units are used as much as is feasible.

Hydropower usually has limited availability of energy relative to its installed capacity. Power and energy produced by conventional hydropower plants are subject to a large number of variations in water supply, environmental constraints, minimum flow requirements, storage, etc. With such variations from season to season or from day to day, a hydropower plant often cannot be assigned to just one of the three generating capacities (base,intermediate, or peaking) because in fact, many hydropower plants will operate under the three generation types at different times of year. From the viewpoint of economics and reduction of oil consumption, the ideal operating time for hydropower is during the peaking hours.

Whether such operation is or is not possible will depend on limitations that may be imposed on daily discharge variations for environmental reasons. A hydropower plant with sufficient storage to release water in desired amounts at any time of year may be base, peaking, or both depending upon permissible daily discharge variations and its greatest value to the power system. Appendix A in its section on Evaluating Hydropower Characteristics gives a more detailed explanation of hydropower utilization. Based on a regional or subregional appraisal, existing and potential hydropower capacity is evaluated, and an estimation of hydropower capacity under each generating type is given.

Because of its characteristics, hydro-pumped storage usually is best suited to provide peaking capacity and energy. Although at the present time there are only a limited number of pumped-storage plants, the installed capacity is expected to increase because of the economic benefits and the potential reduction in oil consumption in displacing oil-fired peaking. The current impetus to convert oil-fired base generation to coal will make pumped storage increasingly attractive because of the low cost of peaking energy so derived. However, environmental constraints and regulations are limiting and impeding their development. Underground pumped storage is being investigated as an answer to environmental objections.

Other forms of energy storage, such as compressed air, battery, flywheel, hydrogen, magnetic field, and heat storage are being studied and developed. By year 2000, it is expected that some of these devices

will be in use for peaking operation. Other sources of energy such as wind, geothermal, direct solar, and biomass, will continue their development. Under normal economic conditions, no major installation would be expected before year 2000. The stimulus being given by governmental action may accelerate the application of the new energy sources. In this study, the conservative approach is adopted.

In view of the foregoing characteristics of generating units, utility systems have a number of options in planning future generation. Some managements prefer to design new units for particular service; others prefer to put newest units into base service and relegate older units to intermediate, peaking, or reserve status as they near retirement age. Managements and management philosophy can change with passage of time, with the nature of the changes not being predictable. To reflect the uncertainties and the many factors which affect the future generation mixes, a range of the future installed capacity for each major generation type is evaluated in this study. For future hydropower capacity, the range reflects the difference between the "committed" hydro projected by the utilities and an estimation of the total potential that could be developed.

Specific Role of Hydropower

The existing and planned hydropower capacity and energy in each region and subregion is discussed. The portions of the regional demand which could be satisfied by hydropower resources are indicated, and future hydropower development is compared to hydropower potential. The existing and planned pumped-storage capacity and energy in each region and subregion is also discussed. Based on regional characteristics and availability of low-cost off peak energy, future pumped-storage capability is estimated.

In addition, Appendix A describes a computer program which has been developed as a part of this study to produce future weekly load curves, and to analyze how new hydropower plants could fit into a power system.

Chapter II

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT FUTURE ELECTRIC POWER DEMAND AND SUPPLY

Introduction

This chapter presents future electric demands and power resources in the East Central Reliability Coordination Agreement (ECAR) and assesses potential for utilization of new hydropower resources. The assessment includes fixed factors and projection of variable factors to the year 2000, among which are the following:

1. Population and economic growth,
2. Electric power and energy demand,
3. Hydropower potential,
4. Availability of fuel resources,
5. Characteristics of electric loads,
6. Generation mix by type of fuel, and
7. Hydropower utilization.

The underlying assumptions and methodology of the projections presented in this chapter are described in Chapter I. In addition, an in depth discussion of load curves, attractiveness of hydropower, and projection sensitivity are presented in Appendices A, B, and C respectively. The combination of Chapter I, this chapter and the appendices summarizes the future electric-energy demand and supply, and the potential role of hydropower in the ECAR region.

The ECAR region covers the east central part of the United States. The ECAR boundaries and its location relative to other councils are shown in Exhibit I-1. The 26 bulk power system members of ECAR are grouped under six subregion as follows:

APS - Allegheny Power System,
AEP - American Electric Power System,
CAPCO - Central Area Power Coordination Group,
CCD - Cincinnati-Columbus-Dayton Group,
KY-IND - Kentucky-Indiana Group, and
MECS - Michigan Electric Coordinated System.

In addition to the bulk power member systems, there are twelve electric utilities that maintain liaison membership with ECAR.

An overview of the electrical situation with emphasis on the role of hydropower in ECAR for 1978 is discussed in Volume III, Chapter II. Included in that volume are a description of power systems which are bulk power suppliers in ECAR, an analysis of the 1978 regional electrical—power demand and supply, and a load resource balance.

Demographic and Economic Growth

Sheet 1 of Exhibit II-1 summarizes the significant demographic and economic data for ECAR; Sheets 2 through 7 summarize the data for the six subregion as approximated by the selected BEA economic areas discussed in Chapter I. A list of the BEA areas comprising each subregion is presented in Exhibit I-2. The projections are based on the 1972 OBERS projections [1].1/

The population growth of ECAR is projected to slow from the historical average annual growth rate of 1.1 percent between 1950 and 1970 to an annual growth rate of 0.7 percent between 1980 and 2000, The ECAR population is expected to increase from 35 million in 1977 to about 42 million in 2000 representing 16% of the total U.S. population. Breakdown by subregion is shown below.

Subregion	Percent of ECAR Population 1970	2000
	%	%
APS	13.3	11.4
AEP	16.2	16.3
CAPCO	18.2	17.5
CCD	9.9	10.1
KY-IND	18.0	19.5
MECS	24.4	25.2

1/ Numbers in brackets refer to references which appear at the end of the report.

Total earnings in the ECAR region are expected to grow at an average annual rate of 3.3% during the study period. The ECAR earnings in constant 1967 dollars are expected to increase from $90 billion in 1970 to $265 billion in 2000. However, the ECAR share of national earnings is decreasing, from 18% in 1970 to an estimated 16% in 2000. The manufacturing sector has the largest growth rate. Individual subregion sectoral earnings are generally projected to follow the same patterns of growth as the overall region sectoral earnings. The Michigan Electric Coordinated System has the largest share of the ECAR earnings. Allegheny Power System, and Cincinnati-Columbus-Dayton Group each represent the smallest shares—10% of the regional total earnings.

Per capita income in the ECAR region is expected to increase at the annual rate of 2.6% until 1990, then at 2.9% to the year 2000. There is a great disparity between the ECAR subregions. The American Electric Power subregion is projected to have the lowest per capita income in ECAR, $4,000 in 1980, and $7,200 in 2000. By contrast, Michigan Electric Coordinated System is projected to have one of the highest per capita incomes of the Nation, $5,150 in 1980 and $8,700 in 2000. The four other subregions are expected to maintain their per capita income at about the national level of $4,780 in 1980 and $8,165 in 2000.[1/]

Future Electric Power Demand

As discussed in Chapter I, three projections of electricity demand are developed for use in assessing the regional market for hydropower [4, 5, 17]. From these, the "median" projection is selected. The OBERS population forecasts are adjusted to reflect the latest census [2] as described in Chapter I. The future electricity demand and adjusted population projections for the total ECAR area, including the six subregions and the liaison members are shown on Sheet 1 of Exhibit II-2. Sheets 2 through 7 of Exhibit II-2 summarize the projections for the six subregions The projections made for the six subregions do not include the liaison members. The liaison members of ECAR accounted for about five perent of the total ECAR energy demand in 1978.

Energy Demand

The "median" ECAR annual demand is expected to grow from 369,100 GWh in 1978 to about 930,400 GWh in 2000. The regional annual growth

1/ The per capita incomes are in constant 1967 dollars.

rate is projected to remain at about 4.5% until 1995, then decrease to 3.5%. The Kentucky-Indiana subregion has the largest share of the regional energy demand which is expected to increase from 79,900 GWh in 1978 to 221,800 GWh in 2000. It has also the highest annual growth rate at about 4.8% over the 1978-2000 period. American Electric Power subregion has the second largest energy demand, which is expected to increase from 73,900 GWh in 1978 to 186,800 GWh in 2000. Michigan Electric Power System and Central Area Power Coordination Group have the lowest projected annual growth rate, 3.3% over the 1978-2000 period. Allegheny Power System has the smallest energy demand, expected to increase from 30,900 GWh in 1978 to 74,400 GWh in 2000, at an annual average growth rate of 4.1%.

Peak Demand

ECAR has both winter and summer peaking systems. The ECAR region as a whole is expected to have a winter peak slightly higher than the summer peak. In 1985, the non coincidental peak demand for ECAR as forecast by the utilities is 88,215 MW in winter, and 85,069 MW in summer. In 2000, the non coincidental peak demand is expected to increase to 163,400 MW, at an average annual growth rate of 4.4% over the 1978-2000 period. The trends in peak demand are similar to the trends in energy growth discussed above. Allegheny Power System, American Electric Power System, and Kentucky-Indiana subregions have projected their highest power demand in winter, whereas the other three subregions expect summer peaks.

Load Factor

In 1978, the ECAR region had one of the highest regional load factors in the Nation (66.6%) because of its heavy industrial load. The Cincinnati-Columbus-Dayton Group and Kentucky-Indiana, which have a lesser proportion of heavy industry, have the lowest load factors, between 58 and 59%. The other subregions are expected to keep their load factors at about 65%.

Estimate of Electric Power Supply

This section discusses major sources of electric power supply to be considered in developing future expansion plans for power capacity additions in ECAR. The hydropower potential is presented, followed by a discussion on the regional fuel availability.

Hydropower Potential

The data in this section is based on earlier reports and is only used in this volume to provide an indication of the regional hydroelectric power potential. The data is principally used in developing the future generation mix. More definitive information on hydropower potential is contained in the regional report on ECAR.

The ECAR region contains both mountainous and flat country with rainfall above the national average, and large streams. Theoretically the hydropower potential is very large; practically, widespread development along rivers restricts hydropower development. Nevertheless, several thousand MW of conventional hydropower, and almost unlimited hydroelectric pumped storage are available.

Table II-1 summarizes the undeveloped hydropower potential based on a 1976 inventory, compiled by the Federal Energy Regulatory Commission, of developed and undeveloped sites with potential capacity greater than 5 MW [6], and preliminary studies (1977) by the Institute for Water Resources (IWR) of potential at existing dams [7]. The IWR

Table II-1

ECAR
UNDEVELOPED HYDROPOWER POTENTIAL

		Potential Installed Capacity (MW)	Average Annual Energy (1000 MWh)
Undeveloped Sites (greater than 5 MW)			
	AEP	2,340	7,976
	APS	1,042	2,563
	CAPCO	0	0
	CCD	15	40
	KY-IND	1,282	3,680
	MECS	165	439
	ECAR	4,844	14,968
Undeveloped at Existing Dams			
	ECAR	4,143	10,135
Total Potential		8,987	25,103

estimate of potential at existing dams is unrestricted with respect to size, and includes dams with a potential installed capacity of less than 5 MW. In 1978, the total hydroelectric capacity in ECAR was about 900 MW, with an energy production of 1,100 GWh.

The Federal Energy Regulatory Commission lists about 100 undeveloped sites in the ECAR region, with total estimated capacity of about 4,800 MW and an energy potential of 15,000 GWh. Potential capacity of sites protected by the Wild and Scenic River Act is not included in Table II-1. However, sites on a number of rivers, such as the Manistee and Au Sable Rivers in Michigan, and sites on other rivers or river segments might be restricted from development because of pending studies under Section 5(a) of the Act.

The estimated capacities of undeveloped identified sites vary greatly, from a few MW to several hundred MW. The American Electric Power System subregion has the largest hydropower potential, about 2,340 MW. The major sites are on the Ohio, New, Kanawha, and Gauley Rivers. The Allegheny Power System and Kentucky-Indiana subregions each have a hydropower potential greater than 1,000 MW. The State of Indiana has 8 potential identified sites of 15 to 75 MW while Kentucky has 20 sites with a capacity of a few MW to 180 MW. The three other subregions in ECAR have very limited hydropower potential.

The Institute for Water Resources in 1977 estimated a hydropower potential of about 3,500 MW at existing dams in the Ohio River Basin. More than half of this potential would come from developments of less than 5 MW. There is a large potential for small-head hydropower development with more than 2,400 dams having a maximum height of 50 feet.

Availability of Fuels

The ECAR area encompasses a major portion of the Appalachian coal fields. Coal is abundant and is available in proximity to the electric load centers. Appalachian coals are for the most part of a high sulfur content requiring the use of scrubbers or the treatment of coal before combustion to satisfy environmental standards. Mixing western low sulfur coal is an alternative, but it incurs increased transportation costs [8, 9, 10].

Nuclear powerplants, are expected to represent an increasing share of the thermal energy sources. The investment costs have been recently

increasing at a high rate due to the lengthening of the lead time and to the addition of safety and environmental devices. The nuclear fuel costs has more than quadrupled in recent years following the sharp increases in crude oil prices. The average price of uranium (U_3O_8) was about \$8/lb in 1972 and has reached \$40/lb in 1978 for long term contracts; spot prices may be much higher. Because of these increases and the uncertainty on the "back end" costs of the fuel cycle, it cannot be taken for granted that nuclear energy will be the cheapest energy source for ECAR considering the abundant coal resources nearby [10, 11].

The ECAR System, except in the Michigan Electric Coordination System, presently has very few oil-fired steam plants. This is fortunate with the shortage of oil and its high cost relative to other fuels.

Load Resources Analysis

This section discusses reserve margins, seasonal system load characteristics, and the specific role of hydropower.

Reserve Margin and System Reliability

In general, the utilities in ECAR project that their reserve margin should remain at or above 20% [17]. For the whole ECAR region, including the liaison members, the reserve margin is projected to be much higher, above 28% for the next decade. However, as discussed in Chapter I, a minimum reserve of 17%, and a maximum of 25% is applied to compute future generating capacities. Within this range, the reserve margin is based on the utilities projections, and summarized in Table II-2. After 1985, imports, exports and interruptible demands have been considered only to the extent that they are included in the utilities projections of resources to serve demand.

Table II-2

RESERVE MARGINS
(Percent of Annual Peak)

	1985	1990	1995	2000
	%	%	%	%
Allegheny Power System	25	25	20	20
American Electric Power System	20	20	20	20
Central Area Power Coordination Group	25	25	21	21
Cincinnati-Columbus-Dayton Group	23	23	23	23
Kentucky-Indiana Group	25	20	20	20
Michigan Electric Coordinated System	25	25	25	25

To enhance its system reliability, ECAR systems have direct interconnections with systems in four other regions, and participate in many interregional activities. Operating studies are made jointly with all neighboring regions prior to each winter and summer peak season. In addition, interregional studies for the year 1988 were performed during 1978 as a part of the activities related to the MAAC-ECAR-NPCC, VACAR-ECAR-MAAC, and MAIN-ECAR-TVA interregional agreements. Furthermore, to provide mutual assistance during emergency conditions, emergency transfer capabilities for 1988 as projected by the NERC regions are shown in Table II-3 [18].

Table II-3

ECAR
EMERGENCY TRANSFER CAPABILITIES
BETWEEN RELIABILITY COUNCILS (MW)
Summer 1988

From		To
ECAR	4,000	MAIN
MAIN	2,800	ECAR
ECAR	4,000	TVA
TVA	5,000	ECAR
ECAR	3,600	VACAR
VACAR	5,500	ECAR
ECAR	5,200	MAAC
MAAC	2,650	ECAR
ECAR	3,100	NPCC
NPCC	2,000	ECAR

Characteristics of Electric Loads

The weekly load curves for the first week of April, August, and December 1977 of representative utilities in ECAR are presented in Volume III, Exhibit II-6. Table II-4 presents a breakdown of these loads (base, intermediate, and peak) for each of these utilities as explained in Chapter I. These percentages are representative of each season. During each season the loads may vary by several percent.

Table II-4

LOAD DISTRIBUTION IN ECAR
(Percent of Annual Peak Load)

Sub-region Representative System	Base %	Inter- mediate %	Peak %
Allegheny Power System:			
West Penn Power Company			
Off Season	66	13	8
Summer	60	17	9
Winter	74	16	10
Annual	74	16	10
American Electric Power System:			
American Electric Power System			
Off Season	66	11	8
Summer	62	16	7
Winter	78	15	7
Annual	78	14	8
Central Area Power Coordination Group:			
Ohio Edison System			
Off Season	59	16	6
Summer	66	24	10
Winter	69	15	9
Annual	69	21	10
Cincinnati-Columbus-Dayton Group:			
Cincinnati Gas and Electric Company			
Off Season	48	13	5
Summer	63	24	13
Winter	62	17	8
Annual	63	24	13
Kentucky-Indiana Group:			
Public Service Company of Indiana			
Off Season	55	15	5
Summer	64	22	14
Winter	70	18	9
Annual	70	16	14
Michigan Electric Coordinated System:			
Detroit Edison Company			
Off Season	50	17	5
Summer	68	20	12
Winter	58	16	7
Annual	68	20	12

From the load curves presented in Volume III, corresponding seasonal tabulations of energy are derived using the computer program described in Appendix A. These tabulations are presented in Exhibit II-3 for each of the representative utilities mentioned above. The use of this information for evaluating hydroelectric power potential is also discussed in Appendix A.

Generation Mix

This section presents future expansion plans. As discussed in Chapter I, an estimate of suggested generation mix for base, intermediate, and peaking capacities is evaluated for ECAR and each of its six subregions. These evaluations are based on existing and planned generation facilities as reported by the utilities, characteristics of electric loads, an analysis of regional resource availability, economic parameters, Federal and state regulations, and other pertinent regional factors. To reflect the uncertainties and unforeseeable factors which can affect future generation mixes, a range of future installed capacity is defined for each major generation source. The projected future capabilities are based on the "median" demand, and the reserve margins presented in Table II-2.

ECAR Regional Summary. Table II-5 presents the most probable generation mix for ECAR. Coal and nuclear-fueled electric generation capacity will dominate in the region. Because of the large regional coal reserves, the present large dependence on coal-fired plants is expected to continue, although its percentage of total capacity will probably decrease. Nuclear will significantly increase its present share as it is used to supply low-cost energy for use in energy storage plants. The percentage of nuclear as shown in the Table II-5 is lower than the utilities forecasts while coal is slightly higher. This difference is an attempt to reflect the impacts that the Three Mile Island incident might have on new nuclear powerplants. Oil and gas-fired plants will all but be eliminated by 2000, and conventional hydropower and pumped storage will supply a large part of the peak load requirements. Other generation sources such as wind and solar, and other energy storage facilities such as compressed air and batteries, are expected to supply about 3% of the ECAR capacity by the year 2000.

Table II-5

ECAR
GENERATION MIX
(Percent of Total Capability)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	11-13	13-15	15-18	15-18
Coal	55-57	52-54	50-53	50-53
Oil	1-3	0	0	0
Intermediate				
Coal 1/	18-20	20-22	22-24	22-24
Oil	3-4	2-4	1-3	1-2
Conv. Hydro	0-1	0-1	0-1	0-1
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	5-7	4-6	3-5	2-4
Gas	1	0-1	0-1	0-1
Conv. Hydro	0-1	0-1	0-1	0-1
Pumped Storage	2	2-3	2-3	2-5
Other	0	0-1	0-1	1-2
Total Capability (GW)	110.2	138.3	172.4	204.3

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Allegheny Power System. Table II-6 presents the probable generation mix for APS. APS does not presently have a nuclear powerplant. Although none are planned for the next decade, some were under consideration, and nuclear could represent about 6% of the 2000 generation mix. Because of the large regional reserves, coal-fired steam units will continue to produce the base load generation other than that which nuclear power might provide. Smaller less efficient coal-fired units will be used more and more for intermediate and peaking operations. Oil-fired units are expected to be completely discontinued by the year 2000. APS is endeavoring to install a large (1,000 MW) pumped-storage facility in West Virginia, but to date has been unable to obtain the necessary clearances. However, by the year 2000, a total capacity of 2,000 MW of pumped storage could be installed. As discussed above in the section on Hydropower Potential, about 1,000 MW of contentional hydropower are undeveloped. If it is considered that some of this potential could be developed in addition to new developments at existing dams, the hydropower capacity could increase by as much as 500 MW by 2000.

Table II-6

ALLEGHENY POWER SYSTEM
GENERATION MIX
(Percent of Total Capability)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	0	0	0	0-6
Coal	73-75	73-75	73-75	68-75
Intermediate				
Coal 1/	20-22	20-22	18-22	18-22
Conv. Hydro	0-1	0-1	0-1	0-1
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	5-6	4-5	2-3	0-2
Conv. Hydro	0-1	0-1	0-2	0-3
Pumped Storage	0	0-8	7-8	6-8
Other	0	0-1	0-1	1-2
Total Capability (GW)	9.2	12.0	13.6	16.0

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

American Electric Power System. Table II-7 presents the probable generation mix for AEP. AEP relies primarily on coal to produce its electric energy; it is expected to so continue in the future. Nuclear capacity probably will increase but it it not expected to exceed 10% of the total power generation. There is a large potential of undeveloped hydropower at new sites and at existing dams in this subregion. There are sites that would permit hydropower capacity to increase from 500 MW in 1978 to about 1,500 MW. AEP already has endeavored to construct large hydroelectric pumped-storage plants, but has been unable to obtain the necessary clearances. However, pumped storage, whether conventional or underground, could represent about 6% of AEP's total capacity in the year 2000.

Table II-7

AMERICAN ELECTRIC POWER SYSTEM
GENERATION MIX
(Percent of Total Capacity)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	9-10	8-9	8-10	8-10
Coal	68-69	68-70	68-70	67-70
Intermediate				
Coal 1/	16-17	16-18	16-18	14-18
Conv. Hydro	1-2	1-2	1-2	1-2
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	1-2	1-2	1-2	0-1
Conv. Hydro	1-2	1-2	1-2	1-2
Pumped Storage	1	1	1	1-6
Other	0	0-1	0-1	1-2
Total Capability (GW)	21.9	26.6	32.4	39.5

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Central Area Power Coordination Group. Table II-8 presents the probable generation mix of CAPCO. CAPCO is expected to have the largest increase in nuclear power during the next decade. From a capacity of 1,200 MW in 1977, nuclear is expected to increase to about 6,000 MW in 1988. However, because of delays in licensing and additional safety and environmental requirements, some units could be postponed. Although new units are planned for the following decade, the percentage of nuclear capacity is not expected to exceed 25% of total system capacity through the year 2000. Presently, there is no conventional hydropower, and only one pumped-storage plant in CAPCO (Seneca, 365 MW). Having such a large percentage of nuclear and coal-fired base load plants, additional conventional or underground pumped-storage appears to be very attractive. A capacity of 2,000 MW is projected for the year 2000.

Table II-8

CENTRAL AREA POWER COORDINATION GROUP
GENERATION MIX
(Percent of Total Capacity)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	20-22	20-22	20-25	20-25
Coal	48-50	48-50	47-52	47-52
Intermediate				
Coal 1/	19-20	21-22	20-22	18-22
Conv. Hydro	3-4	1-3	1-3	0-2
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	4-6	3-5	2-4	0-3
Pumped Storage	2	2	1-2	1-6
Other	0	0-1	0-1	1-2
Total Capability (GW)	17.7	20.6	23.5	27.6

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Cincinnati-Columbus-Dayton Group. Table II-9 presents the probable generation mix of CCD. CCD relies primarily on coal for its electric generation; it is expected to so continue. Nuclear porbably will be increased for base load generation, but nuclear capacity is not expected to exceed 10% of the total generation by the year 2000. There is no significant hydropower generation, and it appears that no pumped-storage plants are planned. However, to meet future peak or even intermediate demand, about 1000 MW of underground or conventional pumped-storage capacity are projected for the year 2000.

Table II-9

CINCINNATI-COLUMBUS-DAYTON GROUP
GENERATION MIX
(Percent of Total Capacity)

Generation Type	1985	1990	1995	2000
	%	%	%	%
Base				
Nuclear	7	6-8	6-8	6-10
Coal	55-57	56-58	56-58	55-60
Intermediate				
Coal 1/	24-25	26-28	28-30	26-30
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	12-14	8-12	5-8	2-5
Pumped Storage	0	0	0	0-5
Other	0	0-1	0-1	1-2
Total Capability (GW)	11.7	15.0	18.1	21.9

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Kentucky-Indiana Group. Table II-10 presents the probable generation mix of the Kentucky-Indiana Group. Presently, there is no nuclear powerplant. Some large units are planned for 1982 and 1984, and in 1985 the nuclear installed capacity is expected to be about 9% of the total capacity. However, the percentage of nuclear capacity is not expected to exceed 10%. Coal-fired units will continue to produce most of the energy needed. As mentioned before, there is about 1,300 MW of hydropower potential at undeveloped site. A significant part of it can reasonably be developed, in addition to developments at existing dams. This could increase the 1978 capacity of 124 MW to about 500 MW by the year 2000. A pumped-storage capacity of 2000 MW is projected for the year 2000.

Table II-10

KENTUCKY INDIANA GROUP
GENERATION MIX
(Percent of Total Capacity)

Generation Type	1985	1990	1995	2000
	%	%	%	%
Base				
Nuclear	9-10	8-10	7-10	7-10
Coal	59-60	58-60	58-60	57-60
Intermediate				
Coal 1/	24-25	26-28	26-28	25-28
Conv. Hydro	0-1	0-1	0-1	0-1
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	4-5	3-5	2-4	1-3
Conv. Hydro	0-1	0-1	0-1	0-1
Pumped Storage	0	0	0	0-4
Other	0	0-1	0-1	1-2
Total Capability (GW)	27.7	34.7	42.4	51.7

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Michigan Electric Coordinated System. Table II-11 presents the probable generation mix for MECS. MECS currently has large coal and nuclear installations and is the largest user of oil and gas in ECAR. Some new oil-fired units are currently under construction, but the percentage of oil or gas-fired capacity is expected to decrease after 1985. Conventional hydropower generation will remain insignificant because of limited potential. The only pumped storage plant in MECS, Ludington, provided 12% of the total capacity in 1977. Although no new pumped-storage plants are under construction, some could be added. Even so, the total pumped-storage percentage in MECS will most likely drop to about 9% of system capacity in the year 2000.

Table II-11

MICHIGAN ELECTRIC COORDINATED SYSTEM
GENERATION MIX
(Percent of Total Capacity)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	15-17	15-18	15-20	15-20
Coal	48-50	48-50	48-52	48-52
Oil	2-4	0	0	0
Intermediate				
Coal 1/	3-6	6-8	10-12	15-18
Oil	14-15	12-13	9-10	5-8
Conv. Hydro	0-1	0-1	0-1	0-1
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	1-3	1-3	0-2	0-2
Gas	2-4	2-4	1-4	1-4
Conv. Hydro	0-1	0-1	0-1	0-1
Pumped Storage	10	8	7	6-9
Other	0	0-1	0-1	1-2
Total Capability (GW)	18.8	22.4	26.3	31.0

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Specific Role of Hydropower

Conventional Hydropower. As of December 1978, there was an installed generating capability of about 900 MW of conventional hydropower, representing 1% of the total generating capability in ECAR. The energy generated was about 1,100 million kWh, representing 0.3% of the total energy demand [19]. As reported by the utilities, there are only two hydropower plants under construction: Racine (40 MW) and Greenup (75 MW) on the Ohio River. Another hydro project on the Ohio River at Gallipolis Lock and Dam is in the advanced planning stages. In their conceptual planning projections for the years 1989-1998, only AEP and APS plan new hydropower capacity, either conventional or pumped storage. As a result, conventional hydropower will account for decreasing portions of the total system capability. In 1988, conventional hydropower energy is expected to account for only 0.2% of the "median" energy demand. Recently, there have been numerous filings of Preliminary Permit Applications with FERC for hydropower development at other Ohio River locks and dams.

As mentioned in the section on Hydropower Potential, there is about 9,000 MW of hydropower potential in ECAR. Assuming that a third of this potential could be developed, 3,000 MW of conventional hydropower could be added to the system by year 2000. With a 3000 MW addition, the present percentage of ECAR total generation in conventional hydropower capacity would continue and even slightly increase. However, because new hydropower would probably be operated at less than the anticipated system load factor, the percentage of energy in the ECAR system from hydropower would decline as compared to the percentage of the hydropower capacity. The energy produced would be best utilized as intermediate and peaking.

Pumped Storage. As of December 1978 there was an installed generating capability of about 2,400 MW of pumped storage at Smith Mountain, Seneca, and Ludington. The energy generated was about 3,000 million KWh, representing 0.8% of the total energy generated [19]. Another unit will soon start generating at Smith Mountain. The only other pumped-storage plant for which FERC action has been taken is Davis (1000 MW). Although there are no comprehensive studies of potential sites for conventional pumped storage, it can be assumed that, because of the regional topography, some could be developed in the future. Geologic conditions indicate that there is also potential for underground pumped storage in the ECAR region [20, 21]. With an abundance of large nuclear and coal-fired steam plants available to supply pumping energy, the peaking capacity provided by the pumped-storage units could represent 7% of the total installed capacity in year 2000.

Sensitivity Analysis

The projections of future electric demand and supply presented in this chapter are based on numerous factors, each of which is sensitive to public opinion, economics of energy use, and changes in domestic or international policies. The number of variations that could be analyzed is nearly infinite. However, regardless of variations in items, population reflects the ultimate energy use. Of particular importance are variations in projected population growth rates. Such variations will directly affect Projections II and III, since they are based upon per capita energy consumption. Projection I would be indirectly affected as it is based on an aggregation of utility forecasts, each of which may have a different underlying forecast methodolgy. Changes in projected economic growth, rate of implementation of conservation measures, Federal and state regulations, and other regional factors are difficult to gauge but will no doubt affect all of the projections. A general discussion of projection sensitivity is presented in Appendix C.

Changes in the regional population growth rates would definitely affect Projections II and III, and, most likely, the "median" Projection. The following table indicates what effects, if any, selected changes in population growth rates would have on the median projection of electric energy consumption in ECAR.

Percent Change in Population Growth Rates	Percent Change in Energy Demand of Projections II & III in the Year 2000	1/ "New" Median Enegy Demand (GWh)
-50	-6.6	901.3
-15	-2.0	930.4
0	0	930.4
+15	+2.1	930.4
+50	+7.1	930.4

1/ Median energy demand is computed as the median of Projection I (unchanged) and Projections II and III (adjusted as indicated).

Table C-8 of Appendix C presents the percentage changes in Projections II and III due to changes in population growth rates for the individual subregions of ECAR.

In ECAR as well as throughout the country, electric energy conservation measures and load-management measures will most likely be

employed in an attempt to offset rising energy prices regardless of other economic activity. Large-scale adoption of conservation will have an effect on electric generation requirements similar to that of depressed economic conditions in that projected demand for both electric power and energy would be reduced. However, conservation will not impede hydroelectric generation, but rather will point to its value and its contribution to conservation. More likely than not, planned thermal-electric generation will be curtailed.

Conversely, if economic activity were to exceed expectations, future demand for energy might exceed the median projection. However, conservation and load control measures could relieve the capacity situation somewhat, so that electric energy use would increase to a larger degree than would capacity requirement. Under such circumstance, hydroelectric power and energy would provide operating economy and there would be demand for all that could be economically installed.

To summarize, electric capacity and energy demand could vary widely from the projections, but the overall need for national energy conservation will continue to justify the production of hydroelectric energy.

Chapter III

MID-ATLANTIC AREA COUNCIL
FUTURE ELECTRIC POWER DEMAND AND SUPPLY

Introduction

This chapter presents future electric demand and power resources in the Mid-Atlantic Area Council (MAAC) and assesses potential for utilization of new hydropower resources. The assessment includes fixed factors projection of variable factors to the year 2000, among which are the following:

1. Population and economic growth,
2. Electric power and energy demand,
3. Hydropower potential,
4. Availability of fuel resources,
5. Characteristics of electric loads,
6. Generation mix by type of fuel, and
7. Hydropower utilization.

The underlying assumptions and methodology of the projections presented in this chapter are described in Chapter 1. In addition, in depth discussions of load curves, attractiveness of hydropower, and projection sensitivity are presented in Appendices A, B, and C respectively. The combination of Chapter I, this chapter, and its appendices summarizes the future energy demand and supply, and the potential role of hydropower in the MAAC region.

The MAAC region covers approximately 48,700 square miles in the central east coast portion of the country as shown on Exhibit I-1. It is the smallest NERC region in area, and for this study it is not subdivided into subregions.

An overview of the electrical situation, with emphasis on the role of hydropower, in MAAC for 1978 is discussed in Chapter IV of Volume III. Included in that volume are a description of power systems, which are bulk power suppliers in MAAC, an analysis of the 1978 regional electric-power demand and supply, and a projected load resources balance.

Demographic and Economic Growth

Exhibit III-1 summarizes the significant demographic and economic data in the MAAC region for 1980, 1985, 1990, and 2000. The geographic delineation of this region by OBERS BEA areas is included in Exhibit I-2. The projections are based on the 1972 OBERS projections [1].1/

MAAC population is expected to increase from 19.7 in 1970 to about 21.5 million in 1980, and 24.9 million in 2000, at an annual average growth rate of 0.8%. As in the past, MAAC population is expected to represent about 9.5% of the total U.S. population.

Total earnings are expected to grow at an annual average growth rate of 3.3% between 1980 and 2000, slightly lower than the national average. Manufacturing is expected to remain the largest earning sector but services earnings should grow at a much faster rate. By the year 2000 services earnings are projected to be as large as the manufacturing earnings.

Although per capita income in the MAAC region has historically been above the national average and is expected to remain so, the disparity is decreasing. From 15% above the national average in 1950, MAAC per capita income is expected to be about 10% above in 1980, and 8% in 2000. MAAC per capita income is projected to increase to $5,200 2/ in 1980 and $8,800 2/ in 2000.

Future Electric Power Demand

As discussed in Chapter I, three projections of electricity demand are developed for use in assessing the regional market for hydropower [4, 5, 22]. From these, the "median" projection is selected. The OBERS population forecasts are adjusted to reflect the latest census data [2] as described in Chapter I. The future electricity demands, and adjusted population projections for MAAC, are shown in Exhibit III-2.

1/ Number in brackets refer to references which immediately follow Chapter XII.

2/ Constant 1967 dollars.

Energy Demand

The future annual "median" electric-energy demand is expected to grow from 169,800 GWh in 1978 to about 342,700 GWh in 2000. The regional energy growth rate is projected to decrease from an average annual growth rate of 3.6% between 1977 and 1985 to about 3.3% between 1990 and 2000.

Peak Demand

MAAC is a summer peaking region, although some individual power systems have a winter peak. The peak demand is expected to increase from 31,800 MW in 1977 to about 63,200 MW in 2000, representing an annual average growth rate of 3.2% over the 1977-2000 period.

Load Factor

MAAC had a load factor of 61% in 1978. From the projected peak and energy demands forecast by the utilities, future annual load factors for the MAAC region are expected to average 61-62% [22].

Estimate of Electric Power Supply

This section discusses major sources of electric power supply to be considered in developing future expansion plans for power capacity additions in MAAC. The hydropower potential is presented followed by a discussion on the regional fuel availability.

Hydropower Potential

The data in this section are based on earlier reports and are only used in this volume to provide an indication of the regional hydroelectric power potential. The data are principally used in developing the future generation mix. More definitive information on hydropower potential is contained in the regional report on MAAC.

Table III-1 summarizes the hydropower potential at both existing dams and undeveloped sites. Hydropower at undeveloped sites is as identified by the Federal Power Commission (now FERC) in 1976 [6]. The identified sites are restricted to those with potential installed capacity greater than 5 MW. Hydropower potential at existing dams is as estimated by the U.S. Army Corps of Engineers, Institute for Water Resources (IWR) in July 1977 [7]. The IWR estimate of potential at existing dams is unrestricted with respect to size, and includes

dams with a potential installed capacity of less than 5 MW. In 1978, the total installed capacity in MAAC was about 950 MW, and the energy production was 3,249 GWh.

Table III-1

MAAC
UNDEVELOPED HYDROPOWER POTENTIAL

	Potential Installed Capacity (MW)	Average Annual Energy (1000 MWh)
Undeveloped Sites (greater than 5 MW)	2,634	6,522
Undeveloped at Existing Dams	1,441	3,550
Total Potential	4,075	10,072

The capacity of the undeveloped identified sites varies greatly from a few MW to several hundred MW. The main sites are on the Delaware and Susquehanna Rivers. The Institute for Water Resources indicates a potential of 1,441 MW in these two basins of which about 40% would come from small capacity developments of less than 5 MW. A few sites on the Delaware River may be restricted from development because of pending studies under Section 5(a) of the Wild and Scenic River Act. Other sites involve major relocations.

Availability of Fuels

The MAAC region has direct access to the considerable coal resources of the Appalachian region. There are large deposits of bituminous coal in the western part of Pennsylvania, where an estimated reserve of more than 20 billion tons of identified resources occur at depths of 1,000 feet or less. In the eastern part of Pennsylvania, there are deposits of anthracite. These resources coupled with sulfur removal and future developments in coal gasification technologies should allow the MAAC region to continue to rely primarily on coal for electric generation [8, 9, 12].

A large number of units in the eastern portion of MAAC are oil-fired for environmental and past economic reasons. Because of the uncertainties associated with foreign oil supply, increasing prices, DOE action, and other factors, the role of oil-fired units will decrease in the future.

Because of economic attractiveness and diversity in base load generation, it is likely that nuclear additions will continue but at a slower rate than projected previously. There is considerable public antagonism to nuclear power, because Three Mile Island is in MAAC.

A realistic assessment of solar and other non conventional energy sources (biomass, wind, thermal-energy storage, etc.) indicates that they will play a minor role in the electric-energy future in MAAC during this century.

Load Resources Analysis

This section discusses reserve margins, seasonal system load characteristics, probable system generation mix, and the specific role of hydropower.

Reserve Margin and System Reliability

As defined in the MAAC report [22], reserve objectives are established by the Pennsylvania, New Jersey, Maryland (PJM) Interconnection Operating Committees. An Operating Reserve Objective, a Primary Reserve Objective, and a Spinning Reserve Objective are in effect at all times.

Reserve margin as projected by the utilities in the future expansion plans developed in 1979 is decreasing rapidly from the high 1978 level of 45% to about 30% in 1985, and 25% in 1995. However, a maximum of 25% is applied to compute future generating capacities to provide adequate and reasonable supply to meet the "median" peak demand as discussed in the reserve margin section of Chapter I.

To provide mutual assistance during emergency conditions, emergency transfer capabilities for 1988 as projected by the NERC regions are shown in Table III-2 [18].

Table III-2

MAAC
EMERGENCY TRANSFER CAPABILITIES
BETWEEN RELIABILITY COUNCILS (MW)
SUMMER 1988

From		To
MAAC	2,450	NPCC
NPCC	4,400	MAAC
MAAC	2,650	ECAR
ECAR	5,200	MAAC
MAAC	3,750	VACAR
VACAR	4,550	MAAC

Characteristics of Electric Loads

The weekly load curves for the first week of April, August, and December 1977 of PJM are presented in Volume III, Exhibit III-6. Table III-3 presents a breakdown of these loads (base, intermediate, and peak) as explained in Chapter I. During each season the loads may vary by several percent.

Table III-3

LOAD DISTRIBUTION IN MAAC
(Percent of Annual Peak Load)

	Base %	Intermediate %	Peak %
Pennsylvania New Jersey Maryland Interconnection			
Off Season	49	16	5
Summer	63	21	16
Winter	62	14	5
Annual	63	21	16

From the load curves presented in Volume III, corresponding seasonal tabulations of energy are derived using the computer program described in Appendix A. These tabulations are presented in Exhibit III-3 for PJM. The use of this information for evaluating hydroelectric power potential is also discussed in Appendix A.

Generation Mix

This section presents future expansion plans. As discussed in Chapter I, an estimate of suggested generation mix for base, intermediate, and peaking capacities is evaluated for MAAC. These evaluations are based on existing and planned generation facilities as reported by the utilities, characteristics of electric loads, an analysis of regional resource availability, economic parameters, Federal and state regulations, and other pertinent regional factors. To reflect the uncertainties and unforeseeable factors which can affect future generation mixes, a range of future installed capacity is defined for each major generation source. The projected future capabilities are based on the "median" demand, and a reserve margin of 25%.

MAAC Regional Summary

Table III-4 presents the probable generation mix in the MAAC region. The oil-fired units represented about half the generating capacity in 1978. Although some new units are now under construction, the role of oil is expected to decrease sharply in the future. With the considerable resources in coal, the region will rely more and more on this potential. By the turn of the century, MAAC could produce more than half of its electric energy needs from coal or its derivatives. As planned by the utilities, nuclear generation is expected to increase rapidly. Then, although new units are projected to be added in the following decade, the percentage is not likely to exceed 25% of the total capacity. New sources including solar and wind could represent as much as 3% of the total capacity.

Table III-4

MAAC
GENERATION MIX
(Percent of Total Capability)

Generation Type	1985	1990	1995	2000
	%	%	%	%
Base				
Nuclear	25-26	23-25	20-25	20-25
Coal	26-28	30-32	35-38	38-40
Oil	10-12	8-10	5-8	2-5
Intermediate				
Coal 1/	4-6	6-8	8-10	10-15
Oil	12-14	10-12	10-12	8-10
Conv. Hydro	1-2	1-2	0-1	0-1
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	13-15	13-15	10-13	8-10
Conv. Hydro	1-2	1-2	1-2	1-2
Pumped Storage	2	2	2-3	1-3
Other	0	0-1	0-1	1-2
Total Capability (GW)	50.5	57.9	67.1	79.0

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Specific Role of Hydropower

Conventional Hydropower. As of December 1978, there was an installed generating capability of about 950 MW of conventional hydro-

power, representing 2% of the total generating capability in MAAC. The total electric energy generated by conventional hydropower was 3,249 million kWh in 1978, representing 2% of the total energy [III-13]. As reported by the utilities, there are three conventional plants under planning and FERC licensing procedure, Safe Harbor Expansion (188 MW), Holtwood (188 MW), and Raystown (20 MW). However, conventional hydropower will account for decreasing portions of the total system capability. In 1988, hydropower energy is expected to account for only 1.5% of the "median" demand. As shown in Table III-1, there is a potential capacity of about 4,000 MW. Part of it could be developed, and depending on the environmental constraints, the energy produced would be best used as intermediate and peaking.

Pumped Storage. As of December 1978, there were three storage plants (Yards Creek, Muddy Run, and Seneca) with a capacity of 1280 MW, producing 1% of the energy demand. 80% of Seneca is owned by the CAPCO pool in ECAR with 20% being owned in MAAC. Although, at this time, there are no pumped-storage units under construction, the regional geology and topography has potential for conventional or underground pumped-storage facilities [21]. The market potential for pumped-storage peaking plants could be as much as 3% of system capacity by the year 2000. This projection assumes that the MAAC generation mix will be largely nuclear and coal-fired steam for base loads.

Sensitivity Analysis

The projections of future electric demand and supply presented in this chapter are based on numerous factors, each of which is sensitive to public opinion, economics of energy use, and changes in domestic or international policies. The number of variations that could be analyzed is nearly infinite. However, regardless of variations in items, population reflects the ultimate energy use. Of particular importance are variations in projected population growth rates. Such variations will directly affect Projections II and III, since they are based upon per capita energy consumption. Projection I would be indirectly affected as it is based on an aggregation of utility forecasts, each of which may have a different underlying forecast methodolgy. Changes in projected economic growth, rate of implementation of conservation measures, Federal and state regulations, and other regional factors are difficult to gauge but will no doubt affect all of the projections. A general discussion of projection sensitivity is presented in Appendix C.

Changes in the regional population growth rates would definitely affect Projections II and III, and, most likely, the "median" projection. The following table indicates what effects, if any, selected changes in population growth rates would have on the median projection of electric-energy consumption in MAAC.

Percent Change in Population Growth Rates	Percent Change in Energy Demand of Projections II & III in the Year 2000	"New" Median Enegy Demand (GWh) 1/
-50	-6.6	320.0
-15	-2.0	335.7
0	0	342.7
+15	+2.1	349.8
+50	+7.1	367.0

1/ Median energy demand is computed as the median of Projection I (unchanged) and Projections II and III (adjusted as indicated).

In MAAC as well as throughout the country, electric-energy conservation measures and load-management measures will most likely be employed in an attempt to offset rising energy prices regardless of other economic activity. Large-scale adoption of conservation will have an effect on electric generation requirements similar to that of depressed economic conditions in that projected demand for both electric power and energy would be reduced. However, conservation will not impede hydroelectric generation, but rather will point to its value and its contribution to conservation. More likely than not, planned thermal-electric generation will be curtailed.

Conversely, if economic activity were to exceed expectations, future demand for energy might exceed the median projection. However, conservation and load control measures could relieve the capacity situation somewhat, so that electric energy use would increase to a larger degree than would capacity requirement. Under such circumstances, hydroelectric power and energy would provide operating economy and there would be demand for all that could be economically installed.

To summarize, electric capacity and energy demand could vary widely from the projections, but the overall need for national energy conservation will continue to justify the production of hydroelectric energy.

Chapter IV

MID-AMERICAN INTERPOOL NETWORK FUTURE ELECTRIC POWER DEMAND AND SUPPLY

Introduction

This chapter presents future electric demands and power resources in the Mid-America Interpool Network (MAIN) and assesses potential for utilization of new hydropower resources. The assessment includes fixed factors and projection of variable factors to the year 2000, among which are the following:

1. Population and economic growth,
2. Electric power and energy demand,
3. Hydropower potential,
4. Availability of fuel resources,
5. Characteristics of electric loads,
6. Generation mix by type of fuel, and
7. Hydropower utilization.

The underlying assumptions and methodology of the projections presented in this chapter are described in Chapter I. In addition, in depth discussions of load curves, attractiveness of hydropower, and projection sensitivity are presented in Appendices A, B, and C respectively. The combination of Chapter I, this chapter, and the appendices summarizes the future electric-energy demand and supply and the potential role of hydropower in the MAIN region.

The members of MAIN are grouped into three geographical subregions:

1. The Commonwealth Edison subregion, which includes the northern portion of Illinois.

2. The Illinois-Missouri subregion which covers the remaining portion of Illinois and the northeastern portion of Missouri.

3. The Wisconsin-Upper Michigan subregion, which covers Wisconsin and the upper peninsula of Michigan.

An overview of the electrical situation, with emphasis on the role of hydropower, in MAIN for 1978 is discussed in Chapter IV of Volume

III. Included in that volume are a description of power systems which are bulk power suppliers in MAIN, an analysis of the existing regional electrical power demand and supply, and a load resource balance. A map of the MAIN region is shown on the national map on Exhibit I-1.

Demographic and Economic Growth

Sheet 1 of Exhibit IV-1 summarizes the significant demographic and economic projections for MAIN; Sheets 2 through 4 summarize the projections for the three subregions as approximated by the selected BEA economic areas discussed in Chapter I. A list of the BEA areas comprising each subregion is presented in Exhibit I-2. The projections are based on the 1972 OBERS projections [1].

MAIN had about 9.2 percent of the total U.S. population and 10.1 percent of the U.S. total personal income in 1970. The shares of the population and income in MAIN are expected to decrease through the period 1970 to 2000. The distribution of the population within MAIN during 1970 and the projection for 2000 are as follows:

Sub-Region	Percent of MAIN Population 1970	2000
	%	%
Commonwealth Edison subregion	50.3	51.9
Illinois-Missouri subregion	29.3	28.4
Wisconsin-Upper Michigan subregion	20.4	19.7

The population growth of the area is projected to slow from the historical average annual growth rate of 1.3 percent between 1950 to 1970 to an annual growth rate of 0.6 percent between 1980 and 2000, slightly lower than the national average. Population growth in the subregions is projected to closely follow the overall trend in MAIN.

Earnings and total personal income in constant dollars are projected to grow at 3.2 and 3.3% respectively, slightly lower than the national average. No large disparity among the subregions in growth of total earnings is expected. Historically, manufacturing and trade have had the largest earnings in MAIN. But by the year 2000, earnings in services and government sectors are expected to exceed trade earnings.

Per capita income in MAIN has historically been higher than the national average and is expected to remain above national level through the year 2000. However, the disparity between MAIN and national averages of per capita income is expected to decrease.

The Commonwealth Edison subregion is projected to experience higher per capita income than the Illinois-Missouri and Wisconsin-Upper Michigan subregions. However, the growth rate of per capita income between 1985 and 2000 in the Commonwealth Edison subregion is expected to be only 2.6%, while growth of per capita income in the Illinois Missouri and Wisconsin-Upper Michigan subregions is expected to be slightly higher at 2.8 and 2.7%, respectively.

Future Electric Power Demand

As discussed in Chapter I, three projections of electricity demand are developed for use in assessing the regional market for hydropower [4, 5, 23]. From these, the "median" projection is selected. The OBERS population forecasts are adjusted to reflect the latest census [2] as described in Chapter I. The future electricity demands, and adjusted population projections for MAIN, are shown on Sheet 1 of Exhibit IV-2; Sheets 2 through 4 summarize the projections for the subregions of MAIN.

Energy Demand

The future annual "median" electric-energy consumption in MAIN is expected to grow from 168,800 GWh in 1978 to 232,500 GWh in 1985, representing a compound annual growth rate of 4.7%. By the year 2000, electric energy consumption is expected to grow to about 421,400 GWh, representing a compound annual rate of 4.2% between 1978 and 2000.

The Wisconsin-Upper Michigan subregion is expected to have the lowest average growth rate in energy demand, at an annual growth rate of 3.8% between 1978 and 2000. The Illinois-Missouri subregion is expected to experience steady decline in the growth rate of energy demand, from an average of 4.9% between 1978 and 1985 to 3.6% between 1995 and 2000. Due to a projected larger increase in population, the Commonwealth Edison subregion has a steadier growth rate, averaging 4.4% over the period 1978-2000.

Peak Demand

Presently, the three subregions of MAIN are summer peaking regions. The peak demands in the Illinois-Missouri and Commonwealth

Edison subregions are expected to continue occurring during the summer at least until the year 2000. Some utilities in the Wisconsin-Upper Michigan subregion currently have and will continue to have winter peaks. The peak demand in MAIN is expected to grow to from 33,200 MW in 1978 to 84,700 MW in 2000, resulting in an average annual growth rate of 4.3% between 1978 and 2000.

Load Factor

MAIN had an annual load factor of 58.0% in 1978. From the projected peak and energy demands forecast by the utilities, future annual load factors for the MAIN region are expected to average 57% [23]. The Wisconsin-Upper Michigan subregion has the highest load factor, and is projected to remain at 65%. The two other subregions have projected annual load factors between 54 and 56%.

Estimate of Electric Power Supply

This section discusses major sources of electric power supply to be considered in developing future expansion plans for power capacity additions in MAIN. The hydropower potential is presented, followed by a discussion on the regional fuel availability.

Hydropower Potential

The data in this section is based on earlier reports and is only used in this volume to provide an indication of the regional hydroelectric power potential. The data is principally used in developing the future generation mix. More definitive information on hydropower potential is contained in the regional report on MAIN.

Table IV-1 summarizes the hydropower potential at both existing dams and undeveloped sites. Hydropower at undeveloped sites is as identified by the Federal Power Commission (now FERC) in 1976 [6]. The identified sites are restricted to those with potential installed capacity greater than 5 MW. Hydropower potential at existing dams is as estimated by the U.S. Army Corps of Engineers, Institute for Water Resources (IWR) in July 1977 [7]. The IWR estimate of potential at existing dams is unrestricted with respect to size, and includes dams with a potential installed capacity of less than 5 MW. From the two preliminary inventories, potential hydroelectric sites in MAIN seem relatively limited in size and number. Total potential at undeveloped sites is about 650 MW and 1,300 MW at existing dams; an average annual energy production of about 6,650 GWh. In 1978, the installed hydropower capacity was about 500 MW in MAIN, and the energy production was 2.3 million MWh.

Table IV-1

MAIN
UNDEVELOPED HYDROPOWER POTENTIAL

Potential at Undeveloped sites (Greater than 5 MW)	Potential Installed Capacity (MW)	Average Annual Energy (1000 MWh)
Commonwealth Edison subregion	105	531
Illinois-Missouri subregion	346	1,024
Wisconsin-Upper Michigan subregion	200	791
MAIN Total	641	2,346
Potential at Existing Dams		
MAIN	1,295	4,298
Total Potential	1,936	6,644

Although potential hydroelectric sites protected by the Wild and Scenic River Act are not included in Table IV-1, segments of the Gasconade and Wisconsin Rivers have been designated for study under Section 5 (a) of the Wild and Scenic Rivers Act (as of January 1, 1976) are included, and potential capacity of these rivers may be restricted from development.

Undeveloped sites with significant potential are primarily in the Illinois-Missouri subregion. Approximately 100 MW of potential capacity exists with 160 GWh of energy storage in three undeveloped sites on the St. Francis River in Missouri. There are also undeveloped sites of significant size on the Gasconade and Salt Rivers in eastern Missouri. There is a total of approximately 346 MW of undeveloped conventional hydropower capacity in the Illinois-Missouri subregion, with potential annual generation of 1,024 GWh.

In the Wisconsin-Upper Michigan subregion, 200 MW of potential capacity exists at undeveloped sites. The largest undeveloped sites lie on the Wisconsin River, having a total potential of about 70 MW of capacity and about 350 GWh of annual generation. Several low-head sites are located in the upper peninsula of Michigan, all with potential capacities of less than 10 MW.

Total undeveloped capacity in the Commonwealth Edison subregion is limited. Only 105 MW of potential capacity at undeveloped sites with an annual energy of 530 GWh exists in the Commonwealth Edison subregion.

In general, the available sites for conventional hydropower are limited and may be too small for economical development at the present time. Regardless of cost or environmental constraints, the total potential at undeveloped hydropower sites is estimated at 641 MW in MAIN, corresponding to an average annual generation of 2,346 GWh.

The U.S. Army Corps of Engineers has surveyed the national potential for additional hydropower at existing dams. This survey includes numerous small existing dams with a total potential of about 1,295 MW of additional installed capacity at existing dams. Sites with a potential installed capacity of less than 5 MW make up a bulk of the sites, with potential installed capacity amounting to 980 MW. Average annual generation associated with all of the potential sites at existing dams in MAIN amounts to 4,298 GWh.

Availability of Fuels

About 11% of the coal reserves in the contiguous U.S. are in MAIN [8, 9]. Most of this coal is unevenly distributed throughout the region, with major deposits in southern Illinois and a small amount in Missouri. In general, all of the MAIN coal has high sulfur content. Coal with lower sulfur content is imported from Kentucky, Wyoming, Montana, and the Dakotas. The Illinois-Missouri and Wisconsin-Upper Michigan subregions depend heavily on coal because of their proximity to these coal-producing regions. The Commonwealth Edison subregion also depends on coal for a major portion of its generation, but has, existing and committed, a large amount of nuclear generation.

The major problem with mid-western coal is that it is high in sulfur, with combustion producing sulfur dioxide levels in excess of allowable limits. With present technology, the sulfur may be removed before combustion or separated in the stack after burning, but these processes are costly in terms of energy and equipment. Low-sulfur western coal may be burned, but it has low BTU content. Also, use of western low-sulfur coal rather than midwest coal may have severe impacts on the social and economic structure of coal-producing areas in Illinois and Missouri. Currently, coal from the two sources is mixed and political trends favor use of local coal accompanied by suitable flue gas-cleaning equipment.

Breakeven cost analysis between coal and nuclear energy indicates nuclear energy generation might be more economical than base load coal generation [8, 9, 10, 11]. However, uncertainity concerning the future of nuclear fuel sources, environmental restrictions and waste disposal necessitates coal plant additions in future years. New oil-fired plants are not likely to be considered as viable for either peaking or base load plants, because of the uncertainty associated with fuel supplies as well as rapidly increasing prices. Government regulations discourage the addition of gas-fired plants. Current trends are that the portion of system capability associated with oil-fired and gas-fired generation will diminish as existing plants are converted to coal or retired.

Load Resources Analysis

This section discusses reserve margins, seasonal system load characteristics, probable system generation mix, and the specific role of hydroelectric power.

Reserve Margin and System Reliability

For a number of years, MAIN used a method referred to as POPM (probability of positive margin) to determine generation reserve requirements. POPM was designed to examine only the system peak condition, taking into account the probability of the annual peak demand deviating from the forecast value. Now MAIN is using the loss of load probability (LOLP) method, which combines the generation capacity outage probability with the expected daily peak demand to give an expected risk of load exceeding capacity. LOLP also can consider the deviation of daily peak demand from forecast. As a result of this new procedure, recent studies have indicated that a minimum generating reserve of 15% would be adequate for MAIN as a whole.

However, as discussed in the reserve margin section of Chapter I, to provide adequate and reasonable power supply to meet the "median" peak demand, a minimum reserve of 17% and a maximum of 25% is applied to compute future generating capacities. Within this range, the reserve margin is based on the utilities projections, and is summarized in Table IV-2. After year 1985, imports, exports and interruptible demands have been considered only to the extent that they are included in the utilities projections of resources to serve demand.

Table IV-2

RESERVE MARGINS
(Percent of Peak Demand)

	1985 %	1990 %	1995 %	2000 %
Commonwealth Edison subregion	23	17	17	17
Illinois-Missouri subregion	20	20	20	20
Wisconsin-Upper Michigan subregion	17	17	17	17

There are areas in which the reserve margins as projected by the utilities fall below the 17% criterion. However, the regional resources to serve demand as forecast by the utilities are within 1 or 2% of the resources needed to meet the "median" projections. In addition, power and energy exchanges between individual systems and/or other reliability councils are and will be made to maintain individual system margins and the best available supply.

Although there are adequate reserve margins projected throughout the forecast period, any delay of large nuclear or coal plants could cause capacity shortages. Because of licensing problems and recent public skepticism associated with nuclear power, it is reasonable to assume that nuclear plants currently scheduled for service but not under construction may be delayed for two or three years. Implementation of Clean Air Act amendments may also delay the construction of coal plants now planned by one or two years.

To enhance its system reliability, MAIN has two Interregional Reliability Coordination Agreements, a two-party agreement with MARCA and a three-party agreement with ECAR and TVA. These agreements provide for periodic review of the adequacy and reliability of the interregional systems. Coordination with the Southwest Power Pool (SWPP) is accomplished informally through the MAIN systems that are contiguous to SPP and have membership in both regions. Furthermore, to provide mutual assistance during emergency conditions, emergency transfer capabilities for 1988 as projected by the NERC regions are shown in Table IV-3, [18].

Table IV-3

MAIN
EMERGENCY TRANSFER CAPABILITIES
BETWEEN RELIABILITY COUNCILS (MW)
SUMMER 1988

From		To
MAIN	2,800	ECAR
ECAR	4,000	MAIN
MAIN	2,300	MARCA
MARCA	600	MAIN
MAIN	3,100	SERC
SERC	3,500	MAIN
MAIN	600	SWPP
SWPP	1,600	MAIN

Characteristics of Electric Loads

The weekly load curves for the first week of April, August, and December 1977 of representative utilities in MAIN are presented in Volume III, Exhibit IV-6. Table IV-4 presents a breakdown of these loads (base, intermediate, and peak) for each of these utilities as explained in Chapter I. These percentages are representative of each season. During each season, the loads may vary by several percent.

For the three utilities representative of MAIN, the average annual base load varies between 59 and 61%, and the peak load varies between 12 and 19% of the peak annual demand. The portions of the load considered as base, intermediate or peak are the basis for deriving the generation mix.

From the load curves presented in Volume III, corresponding seasonal tabulations of energy are derived using the computer program described in Appendix A. These tabulations are presented in Exhibit IV-3 for each of the representative utilities mentioned above. The use of this information for evaluating hydroelectric power potential is also discussed in Appendix A.

Table IV-4

LOAD DISTRIBUTION IN MAIN
(Percent of Annual Peak Load)

Subregion: Representative Utility	Base %	Intermediate %	Peak %
Commonwealth Edison Subregion:			
Commonwealth Edison Company			
Off Season	44	14	5
Summer	59	26	15
Winter	56	14	6
Annual	59	26	15
Wisconsin-Upper Michigan Subregion:			
Wisconsin Electric Power Company			
Off Season	46	23	9
Summer	60	28	12
Winter	55	23	9
Annual	60	28	12
Illinois Missouri Subregion:			
Union Electric Company			
Off Season	42	10	4
Summer	61	20	19
Winter	52	10	6
Annual	61	20	19

Generation Mix

This section presents future expansion plans. As discussed in Chapter I, an estimate of suggested generation mix for base, intermediate, and peaking capacities is evaluated for MAIN and each of its three subregions. These evaluations are based on existing and planned generation facilities as reported by the utilities, characteristics of electric loads, on an analysis of regional resource availability, economic parameters, Federal and state regulations, and other pertinent regional factors. To reflect the uncertainties and unforeseeable factors which can affect future generation mixes, a range of future installed capacity is defined for each major generation source. The projected future capabilities are based on the "median" demand, and the reserve margins presented in Exhibit IV-2.

MAIN Regional Summary. Table IV-5 shows the most probable generation mix to the year 2000 for MAIN. The most probable plan differs from utilities conceptual planning framework in (a) slightly increased coal-fired capacity, (b) reduced nuclear capacity, and (c) to utilize off peak thermal energy more effectively, it is projected that the market potential for underground or conventional pumped storage is likely to represent as much as 6 percent in year 2000. In addition, is likely that other electric energy generation sources and energy storage systems will appear before the year 2000. It is estimated that other sources, particularly battery and thermal storage systems, will provide approximately 3 percent of MAIN's system capacity by the year 2000.

Table IV-5

MAIN
GENERATION MIX
(Percent of Total Capability)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	26-27	23-25	22-25	22-25
Coal	36-38	38-40	40-42	40-42
Intermediate				
Coal 1/	18-20	23-25	24-27	25-28
Oil	5-7	3-5	2-3	1-2
Conv. Hydro	0-1	0-1	0-1	0-1
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	8-10	8-10	6-8	4-6
Gas	1	0-1	0-1	0-1
Conv. Hydro	0-1	0-1	0-1	0-1
Pumped Storage	1	1	1-3	2-6
Other	0	0-1	0-1	1-2
Total Capability (GW)	56.5	68.1	82.5	100.0

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Commonwealth Edison Sub-region. The probable generation mix for Commonwealth Edison sub-region for the years 1985, 1990, 1995, and 2000 is shown in Table IV-6. It is likely that nuclear additions will continue throughout the period because of general economic attractiveness over coal. However, coal plant additions probably will continue despite strict air quality standards to maintain diversification of generation sources. The potential for large conventional hydroelectric development in the Commonwealth Edison subregion is virtually non-existent due to the relatively flat topography. However, there is large potential for underground hydroelectric pumped storage owing to a large nuclear and coal generating base and the indicated availability of suitable sites. It is estimated that underground pumped storage could represent as much as 7 percent of the total generating capability in the year 2000. Existing oil-fired units are projected to remain in service, although some may be converted to coal. It is unlikely that any new oil-fired units will be added.

Table IV-6

COMMONWEALTH EDISON Subregion
GENERATION MIX
(Percent of Total Capability)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	47-49	43-45	38-40	36-40
Coal	15-17	18-20	22-25	23-26
Intermediate				
Coal 1/	14-16	18-20	21-23	22-25
Oil	7-8	5-7	2-4	0-2
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	12-13	10-12	8-10	5-8
Pumped Storage	0	0	0-4	3-7
Other	0	0-1	0-1	1-2
Total Capability (GW)	24.2	28.4	35.1	43.4

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Illinois-Missouri Subregion. The Illinois-Missouri subregion generation mix projected to the year 2000 is shown in Table IV-7. Coal-fired steam plants are expected to supply a large portion of the base load. A number of nuclear plants are scheduled to be operational by 1985. After 1995, addition of hydroelectric pumped storage and other energy storage systems is likely. Conventional hydroelectric development is expected to be small.

Table IV-7

ILLINOIS-MISSOURI Subregion
GENERATION MIX
(Percent of Total Capability)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	10-11	8-10	7-9	7-9
Coal	51-52	52-54	53-55	53-55
Intermediate				
Coal 1/	22-24	23-25	24-26	25-27
Oil	4-5	3-5	2-4	1-2
Conv. Hydro	1-1	1-1	0-1	0-1
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	6-8	5-7	4-6	3-5
Gas	0-1	0-1	0	0
Conv. Hydro	0-1	0-1	0-1	0-1
Pumped Storage	1	1	1	1-5
Other	0	0-1	0-1	1-2
Total Capability (GW)	22.0	27.4	32.9	39.2

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Wisconsin-Upper Michigan Subregion. The Wisconsin-Upper Michigan subregion generation mix is shown on Table IV-8 projected to the year 2000. The emphasis is expected to be placed on the construction of new coal-fired plants. Oil-fired peaking capacity is expected to decrease slightly as old units are retired. By year 2000 pumped storage is likely to be introduced.

Table IV-8

WISCONSIN-UPPER MICHIGAN Subregion
GENERATION MIX
(Percent of Total Capability)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	14-15	13-15	12-15	12-15
Coal	50-52	50-52	50-53	50-53
Intermediate				
Coal 1/	22-24	23-25	24-26	24-26
Oil	2-3	1-2	1-2	0-1
Conv. Hydro	1	1	1	1
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	7-8	6-8	5-7	4-6
Conv. Hydro	1	0-1	0-1	0-1
Pumped Storage	0	0	0	0-5
Other	0	0-1	0-1	1-2
Total Capability (GW)	10.3	12.3	14.5	17.3

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Specific Role of Hydropower

Conventional Hydropower. As of December 1978, there was an installed generating capability of about 500 MW of conventional hydropower, representing 1.2% of the total generating capability in MAIN. The total electric energy generated by conventional hydropower was 2,307 million KWh in 1978, representing 1.4% of the total energy [19]. As reported by the utilities, there is no new conventional hydropower plant under construction. As a result, conventional hydropower will account for decreasing portions of the total system capability. In 1988, hydropower energy is expected to account for only 0.8% of the "median" demand. As shown in Table IV-1, there is a potential capacity of about 2,000 MW. Part of it could be developed, and depending on the environmental constraints the energy produced should be used mainly for intermediate and peaking demand.

Pumped Storage. As of December 1978, there was only one pumped-storage plant (Taum Sauk) with a capacity of 300 MW in summer and 225 MW in winter. There are none under construction. Although the potential for conventional pumped storage is undoubtedly limited due to the relatively flat topography in the midwest, underground pumped-storage sites are known to exist in areas generally west of the Illinois River, in the northern part of Illinois, and most of Wisconsin [21, 24, 25, 26,]. The market potential for pumped-storage peaking plants could be as much as 6% of system capacity by 2000. This projection is based on the assumption that the MAIN generation mix will continue to contain large portions of nuclear and coal-fired steam plants for base loads. The energy production associated with pumped-storage plants represents a closely optimal usage of low-cost off peak thermal energy.

Sensitivity Analysis

The projections of future electric demand and supply presented in this chapter are based on numerous factors, each of which is sensitive to public opinion, economics of energy use, and changes in domestic or international policies. The number of variations that could be analyzed is nearly infinite. However, regardless of variations in items, population reflects the ultimate energy use. Of particular importance are variations in projected population growth rates. Such variations will directly affect Projections II and III, since they are based upon per capita energy consumption. Projection I would be indirectly affected as it is based on an aggregation of utility forecasts, each of which may have a different underlying forecast methodolgy. Changes in

projected economic growth, rate of implementation of conservation measures, Federal and state regulations, and other regional factors are difficult to gauge but will no doubt affect all of the projections. A general discussion of projection sensitivity is presented in Appendix C.

Changes in the regional population growth rates would definitely affect Projections II and III, and, most likely, the "median" projection. The following table indicates what effects, if any, selected changes in population growth rates would have on the median projection of electric energy consumption in MAIN.

Percent Change in Population Growth Rates	Percent Change in Energy Demand of Projections II & III in the Year 2000	1/ "New" Median Enegy Demand (GWh)
-50	-6.0	403.4
-15	-1.8	417.4
0	0	421.4
+15	+1.9	423.8
+50	+6.4	429.4

1/ Median energy demand is computed as the median of Projection I (unchanged) and Projections II and III (adjusted as indicated).

Table C-8 of Appendix C presents the changes in Projections II and III due to changes in the population growth rates for the individual subregions of MAIN.

In MAIN as well as throughout the country, electric-energy conservation measures and load-management measures will most likely be employed in an attempt to offset rising energy prices regardless of other economic activity. Large-scale adoption of conservation will have an effect on electric generation requirements similar to that of depressed economic conditions in that projected demand for both electric power and energy would be reduced. However, conservation will not impede hydroelectric generation, but rather will point to its value and its contribution to conservation. More likely than not, planned thermal-electric generation will be curtailed.

Conversely, if economic activity were to exceed expectations, future demand for energy might exceed the median projection. However, conservation and load-control measures could relieve the capacity situation somewhat, so that electric-energy use would increase to a larger degree than would capacity requirement. Under such circumstances, hydroelectric power and energy would provide operating economy and there would be demand for all that could be economically installed.

To summarize, electric capacity and energy demand could vary widely from the projections, but the overall need for national energy conservation will continue to justify the production of hydroelectric energy.

Chapter V

MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT FUTURE ELECTRIC POWER DEMAND AND SUPPLY

Introduction

This chapter presents future electric demand and power resources in the Mid-Continent Reliability Coordination Agreement (MARCA) and assesses potential for utilization of new hydropower resources. The assessment includes fixed factors and projection of variable factors to the year 2000, among which are the following:

1. Population and economic growth,
2. Electric power and energy demand,
3. Hydropower potential,
4. Availability of fuel resources,
5. Characteristics of electric loads,
6. Generation mix by type for fuel, and
7. Hydropower utilization.

The underlying assumptions and methodology of the projections presented in this chapter are described in Chapter I. In addition, in-depth discussions of load curves, attractiveness of hydropower and projection sensitivity are presented in Appendices A, B, and C respectively. The combination of Chapter I, this chapter and the appendices summarizes the future electric-energy demand and supply, and the potential role of hydropower in the MARCA region.

The MARCA region covers the upper-midwestern part of the United States. Its geographic boundaries and its position in relation to the other councils are shown in Exhibit I-1.

An overview of the electrical situation with emphasis on the role of hydropower in MARCA for 1978 is discussed in Chapter V, Volume III. Included in that volume are a description of power systems which are bulk power suppliers in MARCA, an analysis of the 1978 regional electric-power demand and supply, and a load resource balance.

Demographic and Economic Growth

Exhibit V-1 summarizes the significant demographic and economic projections for MARCA, as approximated by the selected BEA economic

areas discussed in Chapter I. A list of the BEA areas is presented in Exhibit I-2. The projections are based on the 1972 OBERS projections [1].1/

MARCA had approximately 4.8% of the total U.S. population and 4.5% of the U.S. total personal income in 1970. The share of both national population and income in MARCA is expected to gradually decrease to about 4.0% in the year 2000. Population growth in MARCA is expected to slow from the historical 0.6% annual growth rate to 0.4% for the period 1990-2000. This projected population growth rate is significantly lower than the projected national rate of about 0.7%.

Constant dollar earnings and total personal income in the region are expected to grow at about 3.2% annually. The projected 3.2% earnings growth rate for MARCA is lower than the national average 3.7%. Manufacturing and trade have historically been ranked the highest in in terms of sector earnings. However, by the year 2000, the services and government sector earnings will exceed trade earnings. Agriculture is important in MARCA, accounting for about 17% of all national agriculture earnings over the projected period.

Per capita income in the MARCA region has historically been lower than the national average. The projected per capita income in constant dollars is expected to increase at an average annual rate of 2.8% from 1980 to 2000. The projected per capita income growth rate is slightly higher than the 2.7% for the U.S., thus the disparity between MARCA and national per capita income is expected to decrease.

Future Electric Power Demand

As discussed in Chapter I, three projections of electricity demand are developed for use in assessing the regional market for hydropower [4, 5, 27]. From these, the "median" projection is selected. The OBERS population forecasts are adjusted to reflect the latest census [2] as described in Chapter I. The future electricity demands and adjusted population projections for MARCA are shown in Exhibit VI-2.

Energy Demand

Annual electric energy in MARCA is expected to grow from 92,500 GWh in 1978 to 130,300 GWh in 1985, resulting in an average annual

1/ Numbers in brackets refer to references which immediately follow Chapter XII.

growth rate of 5.0%. Beyond 1985, the growth of total energy consumption is expected to slow. The "median" projection indicates that total electric energy demand will have an average annual growth rate of about 4.5% between 1985 and 1990, and drop to 3.7% between 1990 and 2000. In 2000, the "median" electric-energy demand is expected to be 233,000 GWh.

Peak Demand

Presently, MARCA is a summer peaking system, and is expected to remain so in the future. In 1978, the summer peak was about 18,000 MW. The peak is expected to grow to 26,200 MW in 1985, at an average annual growth rate of 5.5%. In 2000, the "median" peak demand is expected to be 46,500 MW, representing an average annual growth rate of 4.4% for the period 1978-2000.

Load Factor

In 1978, MARCA had an annual load factor of 58.7%. Within MARCA, utilites have annual factors varying between 50 and 66% (Exhibit V-5 of Volume III). From the projected peak and energy demands forcast by the utilities, future annual load factors are expected to average 57%.

Estimate of Electric Power Supply

This section discusses major sources of electric power supply to be considered in developing future expansion plans for power capacity additions in MARCA. The hydropower potential is presented, followed by a discussion on the regional fuel availability.

Hydropower Potential

The data in this section is based on earlier reports and is only used in this volume to provide an indication of the regional hydroelectric power potential. The data is principally used in developing the future generation mix. More definitive information on hydropower potential is contained in the regional report on MARCA.

Table V-1 summarizes the hydropower potential at both existing dams and undeveloped sites. Hydropower at undeveloped sites is as identified by the Federal Power Commission (now FERC) in 1976 [6]. The identified sites are restricted to those with potential installed capacity of greater than 5 MW. Hydropower potential at existing dams is as estimated by the U.S. Army Corps of Engineers, Institute for

Water Resources (IWR) in July 1977 [7]. The IWR estimate of potential at existing dams is unrestricted with repect to sizes and includes dams with a potential installed capacity of less than 5 MW. In 1978, the total installed hydroelectric capacity in MARCA, was about 2,900 MW, and the energy production was 15.5 million MWh.

Table V-1

MARCA
UNDEVELOPED HYDROPOWER POTENTIAL

	Potential Installed Capacity (MW)	Average Annual Energy (1000 MWh)
Potential at Undeveloped Sites (greater than 5 MW)	2,700	8,140
Potential at Existing Dams	5,090	13,300
Total Potential	7,790	21,440

The largest portion of undeveloped hydroelectric sites in MARCA are located in Montana. Potentially, 1,130 MW of installed capacity is available at several sites that could produce 4,120 GWh annually. The largest Montana sites are located on the Yellowstone and Missouri Rivers. In North and South Dakota, there is about 1,800 MW of developed hydroelectric capacity. In the Dakota's, a potential of about 900 MW of hydro capacity exists at existing dams, such as Oahe or Fort Randell in South Dakota, and at undeveloped sites. Remaining undeveloped sites in Nebraska, Minnesota, Iowa, and Wisconsin are numerous but limited in size. There is a total of 772 MW of undeveloped capacity in this four-state area; at each site the potential installed capacity is less than 60 MW.

There are a number of pumped-storage sites available in the MARCA region, but environmental restrictions and difficult geological considerations may hinder development at many of these sites. Most of the MARCA region is generally unfavorable for underground pumped-storage development because of deep cretaceous and tertiary sedimentary rock formations unsuitable for underground caverns. Underground pumped-storage developments may however, be feasible in the eastern two-thirds

of Iowa and Minnesota, and all of Wisconsin, where the underground caverns would be located in precambrian rock [8].

Some potential hydroelectric sites located on a portion of the Upper Mississippi River in Minnesota have been designated for study under Section 5 (a) of the Wild and Scenic Rivers Act (as of January 1, 1976). Potential capacity on the river has been included in Table V-1, but may be restricted from development.

Availability of Fuels

Coal resources in MARCA are primarily lignite and sub-bituminous coal. Rough estimates indicate that recoverable coal resources in MARCA account for 19% of the national coal reserves. Major deposits of coal are found in Montana, North Dakota, and South Dakota. Most of the coal in Montana has a sulfur content of less than 1.0%, but must be deep mined. Most of the coal in the Dakotas has a sulfur content between 1.0 and 3.0%, and can be strip mined [9,10]. The abundant coal could provide adequate resources for extensive development of coal-fired generation and coal gasification plants planned for the future.

Gas and oil resources are virtually nonexistent. Gas and oil required for electricity generation and other purposes is supplied from outside the region.

Shale oil and tar sand deposits in MARCA are nearly non existent. Although, there may be limited deposits of tar sands in western South Dakota, these resources are purely speculative and probably very small in size.

South Dakota is expected to become a significant producer of uranium in the future, perhaps producing about 1.5 thousand tons of uranium by the year 2000.

Load Resources Analysis

This section discusses reserve margins, seasonal system load characteristics, probable generation mix, and the specific role of hydropower.

Reserve Margin and System Reliability

Reserve margins, as forecasted by the utilities to meet their own demand projections, are expected to remain above acceptable levels

until 1984, then may fall below the 15% margin usually required by MARCA. However, as discussed in Chapter I, a minimum reserve of 17% and a maximum of 25% is applied to the future "median" peak demand to compute future generating capacities. Except for the years 1987 and 1988, the projections of future generating capacities made by the utilities are within this range to serve the "median" demand. In these two years, the reserve margin, based on the "median" peak demand, may drop to about 11%.

To enhance the system reliability, MARCA utilities have joint activities between subregional groups, and interregional agreements for emergency transfer capabilities [18], as shown in Table V-2.

Table V-2

MARCA

EMERGENCY TRANSFER CAPABILITIES
BETWEEN RELIABILITY COUNCILS (MW)
SUMMER 1988

From		To
MARCA	600	MAIN
MAIN	2,300	MARCA
MARCA	1,000	SWPP
SWPP	1,000	MARCA
MARCA	100	WSCC
WSCC	100	MARCA

Characteristics of Electric Loads

The weekly load curves for the first week of April, August, and December 1977 of representative utilities in MARCA are presented in Volume III, Exhibit V-6. Table V-3 presents a breakdown of these loads (base, intermediate, and peak) for each of these utilities as explained in Chapter I. These percentages are representative of each season, and the annual loads are the basis for deriving the generation mix. During each season, the loads may vary by several percent.

Table V-3

LOAD DISTRIBUTION IN MARCA
(Percent of Annual Peak)

Representative Utility:	Base %	Intermediate %	Peak %
Nebraska Public Power District			
Off Season	35	11	5
Summer	62	22	16
Winter	60	12	8
Annual	62	22	16
Iowa Electric Light & Power Company			
Off Season	45	16	5
Summer	60	24	16
Winter	64	15	13
Annual	64	20	16

For these two utilities representative of MARCA, the average annual base load varies between 62 and 64%, and the peak load range averages 16%.

From the load curves presented in Volume III, corresponding seasonal tabulations of energy are derived using the computer program described in Appendix A. These tabulations are presented in Exhibit V-3 for each of the representative utilities mentioned above. The use of this information for evaluation of hydroelectric power potential is also discussed in Appendix A.

Generation Mix

This section presents future expansion plans. As discussed in Chapter I, an estimate of suggested generation mix for base, intermediate, and peaking capacities is evaluated for MARCA. These evaluations are based on existing and planned generation facilities as reported by the utilities, characteristics of electric loads, an analysis of regional resource availability, economic parameters, Federal and state regulations, and other pertinent regional factors. To reflect the uncertainties and unforeseeable factors which can affect future generation mixes, a range of future installed capacity is de-

fined for each major generation source. The projected future capabilities are based on the "median" demand, and the reserve margins presented in Exhibit V-2.

MARCA Regional Summary. Table V-4 presents the most probable generation mix to the year 2000. MARCA will continue to rely primarily on coal to produce electricity. For the period 1978-1985, about 8,500 MW of coal-fired capacity additions are planned. It is expected that the nuclear capacity will increase, then remain at about 15% of the total installed capacity. Oil-fired units will be used mainly to provide energy during peaking hours.

Table V-4

MARCA
GENERATION MIX
(Percent of Total Capability)

Generation Mix	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	12-14	13-16	14-18	14-18
Coal	46-48	45-48	44-48	44-48
Conv. Hydro	2-3	1-3	1-3	1-2
Intermediate				
Coal 1/	16-17	18-20	18-20	18-20
Oil	1-2	0-2	0-1	0-1
Conv. Hydro	3-4	3-4	2-3	2-3
Other	0	0-1	0-1	1-2
Peak				
Coal 1/	-	-	-	-
Oil	12-13	12-13	12-14	10-13
Conv. Hydro	3-4	3-4	3-5	3-5
Pumped Storage	0	0	0	0-4
Other	0	0-1	0-1	1-2
Capability (GW)	30.6	38.0	45.6	54.4

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Specific Role of Hydropower

Conventional Hydropower. As of December 1978, there was an installed generating capacity of about 2,900 MW of conventional hydropower, representing 13% of the total capacity in MARCA. The total energy generated was 15,500 million kWh, or 16% of the total demand, [19]. As reported by the utilities, there are no new hydropower plants under construction, and some adverse conditions will reduce the existing capability. In 1988, the hydropower energy is expected to account for only 8% of the "median" demand. As shown in Table V-1, there is a large potential, mainly at existing dams. Part of it could be developed, and hydropower energy could maintain a better share of the energy produced in MARCA, mainly for intermediate and peaking demand.

Pumped Storage. There is no pumped storage plant in MARCA, and none are planned by the utilities. However, a potential pumped-storage project of 1180 MW near the Missouri River at Lake Francis Case is under investigation. With large nuclear and coal-fired base-load plants, the market potential for pumped-storage peaking plants could be as much as 4% of the total capacity by 2000. The energy production associated with pumped-storage plants represents a closely optimal usage of low-cost off-peak thermal energy, and would reduce the dependence on oil for peaking demand.

Sensitivity Analysis

The projections of future electric demand and supply presented in this chapter are based on numerous factors, each of which is sensitive to public opinion, economics of energy use, and changes in domestic or international policies. The number of variations that could be analyzed is nearly infinite. However, regardless of variations in items, population reflects the ultimate energy use. Of particular importance are variations in projected population growth rates. Such variations will directly affect Projections II and III, since they are based upon per capita energy consumption. Projection I would be indirectly affected as it is based on an aggregation of utility forecasts, each of which may have a different underlying forecast methodolgy. Changes in projected economic growth, rate of implementation of conservation measures, Federal and state regulations, and other regional factors are difficult to gauge but will no doubt affect all of the projections. A general discussion of projection sensitivity is presented in Appendix C.

Changes in the regional population growth rates would definitely affect Projections II and III, and, most likely, the "median" projection. The following table indicates what effects, if any, selected changes in population growth rates would have on the median projection of electric-energy consumption in MARCA.

Percent Change in Population Growth Rates	Percent Change in Energy Demand of Projections II & III in the Year 2000	"New" Median Enegy Demand (GWh) 1/
-50	-4.9	221.7
-15	-1.5	229.5
0	0	233.0
+15	+1.5	236.5
+50	+5.1	244.9

1/ Median energy demand is computed as the median of Projection I (unchanged) and Projections II and III (adjusted as indicated).

In MARCA as well as throughout the country, electric-energy conservation measures and load-management measures will most likely be employed in an attempt to offset rising energy prices regardless of other economic activity. Large-scale adoption of conservation will have an effect on electric generation requirements similar to that of depressed economic conditions in that projected demand for both electric power and energy would be reduced. However, conservation will not impede hydroelectric generation, but rather will point to its value and its contribution to conservation. More likely than not, planned thermal-electric generation will be curtailed.

Conversely, if economic activity were to exceed expectations, future demand for energy might exceed the median projection. However, conservation and load-control measures could relieve the capacity situation somewhat, so that electric energy use would increase to a larger degree than would capacity requirement. Under such circumstances, hydroelectric power and energy would provide operating economy and there would be demand for all that could be economically installed.

To summarize, electric capacity and energy demand could vary widely from the projections, but the overall need for national energy conservation will continue to justify the production of hydroelectric energy.

Chapter VI

NORTHEAST POWER COORDINATING COUNCIL FUTURE ELECTRIC POWER DEMAND AND SUPPLY

Introduction

This chapter presents future electric demands and power resources in the Northeast Power Coordinating Council (NPCC), and assesses potential for utilization of new hydropower resources. The assessment includes fixed factors and projection of variable factors to the year 2000, among which are the following:

1. Population and economic growth,
2. Electric power and energy demand,
3. Hydropower potential,
4. Availability of fuel resources,
5. Characteristics of electric loads,
6. Generation mix by type of fuel, and
7. Hydropower utilization.

The underlying assumptions and methodology of the projections presented in this chapter are described in Chapter I. In addition, an in depth discussion of load curves, attractiveness of hydropower, and projection sensitivity are presented in Appendices A, B, and C respectively. The combination of Chapter I, this chapter, and the appendices summarizes the future electric-energy demand and supply, and the potential role of hydropower in the NPCC region.

The NPCC region covers the northeastern part of the United States. Its geographic boundaries and its position in relation to the other councils are shown in Exhibits I-1. NPCC is divided in two subregions: New England and New York.

An overview of the electrical situation with emphasis on the role of hydropower in NPCC for 1978 is discussed in Chapter VI, Volume III. Included in that volume are a description of power systems which are bulk power suppliers in NPCC, an analysis of the existing regional electrical power demand and supply, and a load resource balance.

Demographic and Economic Growth

Exhibit VI-1 summarizes the significant demographic and economic projections for the NPCC region and its two subregions (New England

and New York), as approximated by the selected BEA economic areas discussed in Chapter I. A list of the BEA areas comprising each subregion is presented in Exhibit I-2. The projections are based on the 1972 OBERS projections [1].[1/]

NPCC population is projected to 36.8 million in 2000, representing about 14% of the U.S. population. New England and New York subregions have the same population growth rate of 0.8% for the period 1980-2000, slightly lower than in the past (about 1.2% between 1950 and 1970). The New York subregion population is the largest, representing about 60% of the total NPCC population.

Total earnings and personal income are expected to grow at an annual average growth rate of 3.4% between 1980 and 2000, slightly lower than the national average. Historically, manufacturing has had the largest earnings in New England and New York subregions, and is expected to remain so until 1990. However, services earnings are projected to become larger by the year 2000. Government earnings are expected to grow at an annual average growth rate of 3.9% between 1980 and 2000. From 16.6% of the total 1970 earnings, trade earnings are expected to decrease, representing only 14.3% of the total earnings in 2000.

Per capita income is expected to remain above national levels. NPCC per capita income is expected to increase to about $5,500[2/] in 1980, and $9,000 in 2000, representing an annual average growth rate of 2.6%. The New York subregion has one of the highest per capita incomes in the United States. However, the disparity between NPCC and national average is expected to decrease.

Future Electric Power Demand

As discussed in Chapter I, three projections of electricity demand are developed for use in assessing the regional market for hydropower [4, 5, 28]. From these, the "median" projection is selected. The OBERS population forecasts are adjusted to reflect the latest census [2] as described in Chapter I. The future electricity demands, and adjusted population projections for NPCC and its two subregions are shown in Exhibit VI-2.

1/ Numbers in brackets refer to references which follow immediately Chapter XII.

2/ Constant 1967 dollars.

Energy Demand

The future annual "median" energy demand in NPCC is expected to grow from 198,900 GWh in 1978 to about 425,500 GWh in 2000, representing an average annual energy growth rate of 3.5% between 1978 and 2000. The energy demand in the New England subregion is expected to grow faster from 82,800 GWh in 1978 to 194,400 GWh in 2000 or 4.0%. The "median" energy demand forecasted for the New York subregion is expected to increase at an average annual growth rate of 3.2%. From a demand of 116,100 GWh in 1978, it is expected to double by 2000.

Peak Demand

Utilities in NPCC region are characterized by both summer and winter peaks. In 1978, the highest non coincidental peak demand for NPCC was in August (34,876 MW) but its magnitude was just slightly greater than in winter (33,670 MW in December). The NPCC peak demand is expected to grow to 45,400 MW in 1985, and to 75,300 MW in 2000. New England has a winter peak, expected to increase from 15,100 MW in 1978 to 35,000 MW in 2000, at an average annual growth rate of 3.9%. New York subregion has a lower rate of increase, only 3.3% over the 1978-2000 period. As a whole the New York subregion has a summer peak and is expected to increase from 20,400 MW in 1978 to 41,700 in year 2000.

Load Factor

NPCC had an annual load factor of 65% in 1978. Based on the utilities projections, the load factor in NPCC is assumed to remain at about the same level through the remainder of the century, between 64 and 65%. Individually, the New England and New York subregions are expected to have lower load factors averaging 63%.

Estimate of Electric Power Supply

This section discusses major sources of electric power supply to be considered in developing future expansion plans for power capacity additions in NPCC. The hydropower potential is presented, followed by a discussion on the regional fuel availability.

Hydropower Potential

The data in this section is based on earlier reports and is only used in this volume to provide an indication of the regional hydroelectric power potential. The data is principally used in developing the

future generation mix. More definitive information on hydropower potential is contained in the regional report on NPCC.

Table VI-1 summarizes the hydropower potential at existing dams and at undeveloped sites. Hydropower at undeveloped sites is as identified by the Federal Power Commission (now FERC) in 1976 [6]. The identified sites are restricted to those with potential installed capacity of greater than 5 MW. Hydropower potential at existing dams was estimated by the U.S. Army Corps of Engineers, Institute for Water Resources (IWR) in July 1977 (7). The IWR estimate of potential at existing dams is unrestricted with respect to sizes and includes dams with a potential installed capacity of less than 5 MW. In 1978, the installed hydropower capacity was about 5,250 MW in NPCC, and the energy production was 30.4 million MWh.

Table VI-1

NPCC
UNDEVELOPED HYDROPOWER POTENTIAL

	Potential Installed Capacity (MW)	Average Annual Energy (1000 MWh)
Undeveloped Sites (greater than 5 MW)		
New England	3,080	7,075
New York	907	2,720
NPCC	3,987	9,795
Undeveloped at Existing Dams		
NPCC	8,545	29,800
Total Potential	12,532	39,595

The Federal Power Commission identified about 100 undeveloped sites in the New England subregion and 50 sites in the New York subregion. Potential capacity of sites protected by the Wild and Scenic River Act has not been included in Table VI-1. However, sites on the Penobscot, Shepaug and Delaware Rivers might be restricted from development because of pending studies under Section 5(a) of this Act.

The capacity of the undeveloped identified sites varies greatly from a few MW to several hundred MW. The major sites in the New England subregion are on the Androscoggin, Black, Connecticut, Deerfield, Housatonic, Kennebec, Merrimack, and Millers River Basins. In the New York subregion the Saranac, Raquette, Oswegatchie, Moose, and Hudson River Basins have the greatest possibilities.

There is a large hydropower potential at existing dams in the Upper and Lower Hudson River Basin. Most of the potential developments have a capacity of less than 5 MW, but the total estimate is about 7000 MW. The New England subregion has about 3000 dams, and 95% of them have a height of less than 50 feet. There is a large potential for small-head hydro development.

Availability of Fuels

The high cost of crude oil and continued dependence on foreign oil supply would make further expansion of oil-fired base load generation undesirable. Furthermore, the U.S. goal of balancing domestic supply and demand in the 1980's will have the effect of sharply reducing oil supplies from present levels, even with the completion of the Alaskan pipelines and off shore facilities.

The majority of coal burned in the powerplants of the New York subregion is tansported by rail from Pennsylvania and northern West Virginia. Lesser quantities are transported by truck from Pennsylvania. Limited quantities of low-sulfur coal are shipped by rail and/or water from Lake Erie or east coast terminals. In the New England subregion, there is no significant coal resource. For that reason, transportation is an essential consideration in the use of coal. In addition to cost, transportation of coal necessarily requires consideration of the availability of equipment and facilities, and the reliability of the transportation system. Coal-slurry pipelines or coal gasification could be a better solution [8, 9] although coal-slurry pipelines probably would encounter expensive right-of-way problems.

Extensive economic studies indicate that nuclear generation is the most economic choice for the base load [10, 11, 37]. Utilities are increasing their nuclear capacity. An addition of about 6,000 MW of nuclear capacity is projected between 1978 and 1988 in New England, and about 3,000 MW in New York. This trend is subject to many factors. Uncertainties in the future of nuclear fuels sources and wastes as well as environmental restrictions indicate that other sources for base load generation will be considered.

Among the new sources of energy, no significant potential geothermal sources are known in the NPCC region. Solar energy will find near-term application in building heating. These applications will not produce electric energy but may produce different electric demand patterns where electricity is used as solar back up. Solar thermal-electric power generation is judged unlikely before 2000. Among the solar effects, tidal power is gaining economic applicability. Indications are that the tides of the Bay of Fundy in New Brunswick, Canada can provide an economic source of renewable energy. The utility systems of the Northeastern United States could benefit from such a development. Preliminary assessment of wind-powered generators suggests very high capital cost per unit of energy produced. Only occasional isolated applications will probably occur with a negligible overall effect on electric utilities. Wood-fired generation would be limited to small generating capacities because of the quantity of wood required.

Load Resources Analysis

This section discusses reserve margin, seasonal system load characteristics, probable system generation mix, and the specific role of hydroelectric power.

Reserve Margin and System Reliability

In general, utility reserve margins in NPCC are expected to be well over 20% at the time of the peak demand. For the total region, the margin as reported by the utilities is expected to average 30% throughout the study period. New York subregion has the highest reserve margin, decreasing slowly from over 40% in 1978 to 25% in year 2000. However, as discussed in the reserve margin section of Chapter I, a minimum reserve of 17% and a maximum of 25% is applied to the future "median" peak of each subregion to compute future generating capacities. Within this range, the reserve margins are based on the utilities projections and are summarized in Table VI-2.

Table VI-2

RESERVE MARGINS
(Percent of Peak Demand)

	1985	1990	1995	2000
	%	%	%	%
New England Subregion	20	23	23	23
New York Subregion	25	25	25	25

To enhance its system reliability, New England and New York Power Pools have several intraregional coordination programs. Furthermore, NPCC has interregional agreements with MAAC and ECAR. Table VI-3 shows the emergency transfer capabilities projected for 1988 [18].

Table VI-3

NPCC
EMERGENCY TRANSFER CAPABILITIES
BETWEEN RELIABILITY COUNCILS (MW)
SUMMER 1988

From		To
NPCC	4,400	MAAC
MAAC	2,450	NPCC
NPCC	2,000	ECAR
ECAR	3,100	NPCC

Characteristics of Electric Loads

The weekly load curves for the first week of April, August, and December 1977 of representative utilities in NPCC are presented in Volume III, Exhibit VI-6. Table VI-4 presents a breakdown of these loads (base, intermediate, and peak) for each of these utilities as explained in Chapter I. These percentages are representative of each season. During each season, the loads may vary by several percent.

For the New York subregion, Consolidated Edison Company (Con Ed) and Niagara Mohawk System were selected because they have the two largest peak demands. Consolidated Edison's loads are representative of New York City and the Niagara Mohawk System is more representative of the remainder of the New York subregion.

Table VI-4

LOAD DISTRIBUTION IN NPCC
(Percent of Annual Peak Load)

Subregion: Representative System	Base %	Intermediate %	Peak %
New England Subregion:			
New England Power Exchange			
Off Season	52	18	10
Summer	52	22	14
Winter	63	24	13
Annual	63	23	14
New York Subregion:			
Consolidated Edison Company			
Off Season	33	20	10
Summer	56	24	20
Winter	34	25	11
Annual	56	24	20
Niagara Mohawk System			
Off Season	60	19	5
Summer	58	15	11
Winter	70	20	10
Annual	70	19	11

From the load curves presented in Volume III, corresponding seasonal tabulations of energy are derived using the computer program described in Appendix A. These tabulations are presented in Exhibit VI-3 for each of the representative utilities mentioned above. The use of this information for evaluation of hydroelectric power potential is also discussed in Appendix A.

Generation Mix

This section presents future expansion plans. As discussed in Chapter I, an estimate of suggested generation mix for base, intermediate, and peaking capacities is evaluated for NPCC and each of its

three subregions. These evaluations are based on existing and planned generation facilities as reported by the utilities, characteristics of electric loads, an analysis of regional resource availability, economic parameters, Federal and state regulations, and other pertinent regional factors. To reflect the uncertainties and unforeseeable factors which can affect future generation mixes, a range of future installed capacity is defined for each major generation source. The projected future capabilities are based on the "median" demand, and the reserve margins presented in Exhibit VI-2.

NPCC Regional Summary. Table VI-5 shows the most probable generation mix to the year 2000 for NPCC. Historically, NPCC has relied mainly on oil to produce its energy generation. This trend is changing rapidly. Only a few oil-fired units are now under construction. In the long term (beyond the year 2000), oil-fired base load generators will be completely replaced by nuclear and coal. As projected by the utilities, nuclear capacity is increasing rapidly and is expected to account for about 30% of the 2000 generation mix. Because of the lead-time required to certify sites and secure coal sources, the coal capacity will increase slowly before 1985. After that, it is expected to increase quite rapidly. By year 2000, the coal capacity could represent about 30% of the total generation.

The above relationship between nuclear and coal-fired generating facilities could change in the future in light of the current administration policies and public concern regarding new nuclear power development. As a result, there may be an attempt to construct more coal-fired plants to make up for any nuclear slowdown. However, development of coal-fired plants may also suffer due to environmental concerns such as air pollution and "acid rain" in the highly-populated east coast. As a result, a shortage of base load generation could occur, making future hydropower developments even more attractive.

Table VI-5

NPCC
GENERATION MIX
(Percent of Total Capability)

Generation Mix	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	16-18	23-28	25-28	26-30
Coal	8-10	10-13	16-20	22-25
Oil	34-36	27-30	20-23	10-14
Conv. Hydro	0-1	0-1	0-1	0-1
Intermediate				
Coal	1-2	2-4	3-5	5-8
Oil	13-15	10-12	10-12	8-10
Conv. Hydro	4-5	4-5	3-5	2-5
Other	0	0-1	0-1	1-2
Peaking				
Oil	9-11	8-10	8-10	8-9
Conv. Hydro	4-5	4-5	3-5	3-5
Pumped Storage	5	4-5	4-6	4-6
Other	0	0-1	0-1	1-2
Total Capability (GW)	57.7	68.5	80.4	95.2

New England Subregion. Table VI-6 shows the most probable generation mix for the period 1985-2000. From a system which is the most heavily dependent on oil in the country, New England is rapidly changing its generation mix. With large units of 1150 MW under construction, nuclear capacity is increasing rapidly but, after 1990, it is expected that nuclear capacity will maintain its share of about 30 to 35% of the total capacity. In 1978, there was only about 450 MW of steam coal-fired units. By year 2000, coal base units could provide as much as 25% of the total capacity. Conversion of one large oil-fired station (Brayton Point) already is underway.

Table VI-6

NEW ENGLAND Subregion
GENERATION MIX
(Percent of Total Capability)

Generation Mix	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	21-23	25-30	29-32	31-35
Coal	2-3	5-8	12-15	16-20
Oil	38-40	30-35	22-26	10-15
Conv. Hydro	1-2	1-2	1-2	1-2
Intermediate				
Coal	0-1	1-3	3-5	6-8
Oil	16-18	15-17	13-15	10-13
Conv. Hydro	2-3	2-3	1-2	1-2
Other	0	0-1	0-1	1-2
Peaking				
Oil	7-9	8-10	7-10	8-10
Conv. Hydro	2-3	2-3	2-4	3-5
Pumped Storage	6	5	4	4-6
Other	0	0-1	0-1	1-2
Total Capability (GW)	25.7	30.9	36.0	43.0

New York Subregion. Table VI-7 shows the most probable generation mix to the year 2000. Nuclear capacity is expected to continue its expansion, and could represent as much as 30% of the total capacity by 2000. The coal capacity is increasing slowly but by 2000, a third of the base capacity could be provided by coal-fired units. Although oil-fired units are being retired, derated, or converted, oil will continue to play an important role. By 1995 oil capacity could still represent about 40% of the total capability.

Table VI-7

NEW YORK Subregion
GENERATION MIX
(Percent of Total Capability)

Generation Mix	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	14-15	20-25	22-25	25-30
Coal	12-14	15-20	18-22	20-25
Oil	30-32	25-28	20-23	10-20
Conv. Hydro	3-4	2-4	2-4	2-4
Intermediate				
Coal	1-2	3-5	4-6	5-10
Oil	10-12	8-10	8-10	5-8
Conv. Hydro	4-5	4-5	4-6	3-6
Other	0	0-1	0-1	1-2
Peaking				
Oil	10-11	8-10	8-10	6-8
Conv. Hydro	3-4	3-4	3-5	3-5
Pumped Storage	3	3-5	4-6	4-6
Other	0	0-1	0-1	1-2
Total Capability (GW)	31.9	37.6	44.3	52.2

Specific Role of Hydropower

Conventional Hydropower. As of December 1978 there was an installed generating capacity of about 1,250 MW of conventional hydropower in the New England subregion, representing 6% of the total generating capability. The total energy generated was 4,400 million KWh, representing 5.5% of the total electrical energy [19]. As reported by the utilities, these are several small hydropower plants or additions under construction, planning or licensing among which are Lawrence (17MW), Hadley Falls (15MW), Cold Stream (83 MW), and Great Falls (1.3 MW). However, by 1988, hydropower energy in New England is expected to account for only 2.6% of the electrical energy demand.

In 1978, the New York subregion had an installed capacity of about 4,000 MW of conventional hydropower, representing 13.5% of the total capability. The total energy generated was 26,000 million KWh, representing about 22% of the total electrical energy [19]. As reported by the utilities there are several small hydropower plants or additions under construction, planning or licensing among which are Granby (10 MW), Trenton (9 MW), Hudson Falls (60 MW), Fort Edward (10 MW), Glenn Park (20 MW), and South Glenn Falls (16 MW). Even so, by 1988, hydropower energy in the New York subregion is expected to account for no more than 17% of the electrical energy demand.

As shown in Table VI-1, there is large potential at undeveloped sites and at existing dams. Part of it could be developed. The energy produced will serve base, intermediate or peaking demand depending on site characteristics, environmental constraints and other parameters. Any additional power and energy available from new hydropower development will help reduce the dependence on oil.

Pumped Storage. As of December 1978, there were three pumped-storage plants in New England: Northfield Mountain (1,000 MW), Bear Swamp (600 MW), and two small units at Rocky River (7 MW). The energy produced during peaking hours was 1,175 million KWh or 1.5% of the total demand. Although there are no other pumped-storage plants under construction, the energy output is expected to increase to 2,000 million KWh because of a greater availability of low-cost pumping energy from nuclear and coal-fired plants. By the year 2000, more capacity could be added to the system.

In the New York subregion, Blenheim Gilboa (1,000 MW) is the larger of the two installed pumped-storage plants. The other, Lewiston-Niagara, has an installed pumped-storage capacity of 240 MW. In 1978, the energy output of these two plants was about 1,200 million kWh or 1% of the total energy demand. A license has been granted to Cornwall (2,000 MW), but the applicant has discontinued all work on the project. Another pumped-storage plant is being considered at Prattsville (1,000 MW); it is currently in the planning stage. By year 2000, pumped-storage capacity could represent 6% of the total installed capacity.

Sensitivity Analysis

The projections of future electric demand and supply presented in this chapter are based on numerous factors, each of which is sensitive to public opinion, economics of energy use, and changes in domestic or international policies. The number of variations that could be analyzed is nearly infinite. However, regardless of variations in items, population reflects the ultimate energy use. Of particular importance

are variations in projected population growth rates. Such variations will directly affect Projections II and III, since they are based upon per capita energy consumption. Projection I would be indirectly affected as it is based on an aggregation of utility forecasts, each of which may have a different underlying forecast methodolgy. Changes in projected economic growth, rate of implementation of conservation measures, Federal and state regulations, and other regional factors are difficult to gauge but will no doubt affect all of the projections. A general discussion of projection sensitivity is presented in Appendix C.

Changes in the regional population growth rates would definitely affect Projections II and III, and, most likely, the "median" projection. The following table indicates what effects, if any, selected changes in population growth rates would have on the median projection of electric energy consumption in NPCC.

Percent Change in Population Growth Rates	Percent Change in Energy Demand of Projections II & III in the Year 2000	1/ "New" Median Enegy Demand (GWh)
-50	-6.8	411.6
-15	-2.1	421.2
0	0	425.5
+15	+2.1	429.8
+50	+7.2	440.1

1/ Median energy demand is computed as the median of Projection I (unchanged) and Projections II and III (adjusted as indicated).

Table C-8 of Appendix C presents the changes in Projections II and III due to changes in the population growth rates for the individual subregions in NPCC.

In NPCC as well as throughout the country, electric-energy conservation measures and load-management measures will most likely be employed in an attempt to offset rising energy prices regardless of other economic activity. Large-scale adoption of conservation will have an effect on electric generation requirements similar to that of depressed economic conditions in that projected demand for both electric power and energy would be reduced. However, conservation will not impede hydroelectric generation, but rather will point to its value and its contribution to conservation. More likely than not, planned thermal-electric generation will be curtailed.

Conversely, if economic activity were to exceed expectations, future demand for energy might exceed the median projection. However, conservation and load-control measures could relieve the capacity situation somewhat, so that electric energy use would increase to a larger degree than would capacity requirement. Under such circumstance, hydroelectric power and energy would provide operating economy and there would be demand for all that could be economically installed.

To summarize, electric capacity and energy demand could vary widely from the projections, but the overall need for national energy conservation will continue to justify the production of hydroelectric energy.

Chapter VII

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
FUTURE ELECTRIC POWER DEMAND AND SUPPLY

Introduction

This chapter presents future electric demands and power resources in the Southeastern Electric Reliability Council (SERC), and assesses potential for utilization of new hydropower resources. The assessment includes fixed factors and projection of variable factors to the year 2000, among which are the following:

1. Population and economic growth,
2. Electric power and energy demand,
3. Hydropower potential,
4. Availability of fuel resources,
5. Characteristics of electric loads,
6. Generation mix by type of fuel, and
7. Hydropower utilization.

The underlying assumptions and methodology of the projections presented in this chapter are described in Chapter I. In addition, in-depth discussions of load curves, attractiveness of hydropower, and projection sensitivity are presented in Appendices A, B, and C respectively.

The combination of Chapter I, this chapter and the appendices summarizes the future electric-energy demand and supply, and the potential role of hydropower in the SERC region.

The SERC region covers the Southeastern part of the United States. The SERC boundaries and its location relative to other councils are shown in Exhibit I-1. The SERC region encompasses a large geographical area having four relatively well-defined subregions:

VACAR	-	Virginia Carolinas
TVA	-	Tennessee Valley
SOUTHERN	-	Southern Companies
FLORIDA	-	Florida

An overview of the electrical situation with emphasis on the role of hydropower in SERC for 1978 is discussed in Volume III, Chapter VII.

Included in Volume III are a description of power systems which are bulk power suppliers in SERC, an analysis of the 1978 regional electric power demand and supply, and a projected load resource balance.

Demographic and Economic Growth

Sheet 1 of Exhibit VII-1 summarizes the significant demographic and economic data for SERC and sheets 2 through 5 summarize the data for the four subregions as approximated by the selected BEA economic areas discussed in Chapter I. This approximation by BEA areas may not reflect the actual delineation of the subregions. However, the future trends derived from the BEA areas can be considered as resonably reliable. A list of the BEA areas comprising each subregion is presented in Exhibit I-2. The projections are based on the 1972 OBERS projections [1].1/

The SERC population is projected to represent increasing portions of the national population. From 16.4% of the U.S. population in 1970, the SERC population is expected to grow to 18.7% in year 2000, with about 50 million people. FLORIDA has the highest annual population growth rate (about 1.8%). The other three subregions follow substantially the same projected growth rate as the total region, 1.2% during the 1980-2000 period. The SERC population breakdown by subregion is shown below.

Subregion	Percent of SERC Population 1970	2000
	%	%
VACAR	38.2	37.3
TVA	16.3	15.2
SOUTHERN	25.6	22.3
FLORIDA	19.9	25.2

Total earnings in the SERC region are expected to continue to grow at an average annual growth rate of 4.1% between 1980 and 1990, then at 3.8%. The SERC earnings historically have been representing increasing shares of the national market, and the increase is expected to continue in the future, from 14% of the national total earnings in 1970 to about 16.5% in 2000. Government and services are projected to represent the largest-growing earnings sectors in the SERC region. The manufacturing

1/ Numbers in brackets refer to references which immediately follow Chapter XII.

sector is the second largest industrial sector, but its share of the total earnings is projected to diminish. The government and agriculture sectors in SERC should continue to maintain large percentages of the national earnings in these sectors. Individual subregion sectoral earnings are projected generally to follow the same patterns of growth as the overall region sectoral earnings. The VACAR subregion should continue to produce the largest share, about 40% of the total SERC earnings. It should be noted that due to approximation by BEA areas, VACAR includes the Washington D.C. metropolitan area which should be a part of MAAC. However, this does not greatly affect the results. In the TVA and SOUTHERN subregions, manufacturing is the largest economic sector whereas, in FLORIDA, the services sector is the largest.

Per capita income in the SERC region is expected to increase at an annual rate of 2.8% between 1980 and 1990, then at 3.0% until 2000. Although, the SERC per capita income has historically been below the national average, the disparity should decrease, and by year 2000, SERC per capita income is expected to be about 90% of the national per capita income. Within SERC, the TVA and SOUTHERN subregions have the lowest per capita income, but these two subregions should experience the highest growth rate.

Future Electric Power Demand

As discussed in Chapter I, three projections of electricity demand are developed for use in assessing the regional market for hydropower [4, 5, 29]. From these, the "median" projection is selected. The OBERS population forecasts are adjusted to reflect the latest census [2] as described in Chapter I.

The future electricity demands, and adjusted population projections for SERC are shown on Sheet 1 of Exhibit II-2. Sheets 2 through 5 of Exhibit II-2 summarizes the projections for the four subregions.

Energy Demand

The future annual "median" electric-energy demand is expected to grow from 453,200 GWh in 1978 to about 1,233,000 GWh in 2000 at an average annual growth rate of about 4.7%. The regional energy growth rate is projected to decrease from an average annual growth rate of 5.7% between 1977 and 1985 to about 3.7% between 1995 and 2000. The VACAR subregion has the largest share of the regional energy. The annual energy demand in VACAR is expected to grow from 143,000 GWh in 1978 to about 427,600 GWh in 2000, at an average annual growth rate of

5.1%. Havinơ one of the country's highest population growth rate, the FLORIDA subregion is expected to increase its energy demand from 84,900 GWh in 1978 to 230,100 GWh in 2000, at an average annual growth rate of 4.6%. The energy demand is expected to increase at 4.8% in the SOUTHERN subregion, and 4.0% in the TVA subregion.

Peak Demand

The trends in peak demand are similar to the trends in energy growth discussed above. The peak demand for SERC is expected to grow from 80,500 MW in 1978 to about 232,100 MW in 2000, representing an average annual growth rate of 4.9%. The SERC peak demand is expected to be in winter, but should only be slightly greater than the summer peak. The TVA subregion has a winter peak estimated to be about 15% greater than the summer peak throughout the study period. The VACAR and FLORIDA subregions each have summer and winter peaks of about the same magnitude. The SOUTHERN subregion has a summer peak slightly greater than the winter peak.

Load Factor

In 1978, the load factor in SERC was 64.3%. From the projected peak and energy demands forecast by the utilities, future annual load factors are expected to vary between 61.5 and 60.5%. The TVA subregion has the highest load factor in the region projected to be about 63.5%, while FLORIDA is expected to have the lowest one at about 52.5%.

Estimate of Electric Power Supply

This section discusses major sources of electric power supply to be considered in developing future expansion plans for power capacity additions in MAIN. The hydropower potential is presented, followed by a discussion on the regional fuel availability.

Hydropower Potential

The data in this section is based on earlier reports and is only used in this volume to provide an indication of the regional hydroelectric power potential. The data is principally used in developing the future generation mix. More definitive information on hydropower potential is contained in the regional report on SERC.

Table VII-1 summarizes the hydropower potential at both existing dams and at undeveloped sites. Hydropower at undeveloped sites is as

identified by the Federal Power Commission (now FERC) in 1976 [6]. The identified sites are restricted to those with potential installed capacity of greater than 5 MW. Hydropower potential at existing dams is as estimated by the U.S. Army Corps of Engineers, Institute for Water Resources (IWR) in July 1977 [7]. The IWR estimate of potential at existing dams is unrestricted with respect to size, and includes dams with a potential installed capacity of less than 5 MW. In 1978 there was about 9,800 MW of installed hydroelectric capacity in SERC, producing about 31,200 million KWh of electric energy.

Table VII-1

SERC
UNDEVELOPED HYDROPOWER POTENTIAL

Undeveloped Sites (greater than 5 MW)	Potential Installed Capacity (MW)	Average Annual Energy (1000 MWh)
VACAR	2,613	4,988
TVA	518	1,179
SOUTHERN	3,486	5,818
FLORIDA	83	69
SERC	6,700	12,054
Undeveloped at Existing Dams		
SERC	9,412	35,595
Total Potential	16,112	47,649

The Federal Power Commission lists about 200 undeveloped sites in the SERC region. Potential capacity of sites protected by the Wild and Scenic River Act has not been included in Table VII-1. However, sites on a number of rivers such as the Obed and Nolichucky Rivers may be restricted from development because of pending studies under section 5(a) of this Act. The capacity of undeveloped identified sites varies greatly from a few MW to several hundred MW.

The SOUTHERN subregion has the largest hydropower potential of about 3,500 MW. The principal sites are in Georgia on the Broad, Savannah, Oconee, Chattahoochee, Flint, and Etowah Rivers. In Alabama, the Locust Fork and Tallapoosa Rivers have the largest potential. Some of these sites have a capacity of more than 100 MW. The VACAR subregion also has large hydropower potential. In North Carolina, the principal river basins with the greatest hydropower potential are Cape Fear, Haw, Pee Dee, Rocky, Yadkin, and Broad. In South Carolina, the main basins are Santee, Catawba, Broad, and Savannah. There are some potential sites on the Rappahannock, South Anna, James, and Smith Rivers in Virginia. The FLORIDA subregion has only two sites which probably could be developed, Mac Chenney on the St. Marys River and Crestview on the Yellow River The TVA subregion has several identified sites on the Hiwassee, Obed, Nolichucky, Holston, Little Tennessee, and Elk River.

The Institute for Water Resources forecasts a hydropower potential of about 9,000 MW in the South Atlantic Gulf Basin, and about 400 MW in the Tennessee River Basin. In the South Atlantic Gulf Basin, there are about 7,000 existing dams. Nearly half of the projected potential would come from small capacity developments of less than 5 MW. Within this region the main basins to be developed are Alabama, Savannah-Ogeechee, Appalachicola, and Roanoke. In the Tennessee River Basin, 75% of the hydropower potential would come from the Rehabilitation Potential at existing dams, forecast by the Institute. There is a potential of about 75 MW at small dams with capacity of less than 5 MW.

Availability of Fuels

In 1977, half of the SERC electric energy was generated by coal-fired units. The SERC region has direct access to the considerable coal resources of the Appalachian region. In the SERC region itself, the major coal deposits are in Alabama and Tennessee. The total eastern region of the United States has more than 100 billion tons of identified resources, mostly bituminous coal, at occurring depths up to 1000 feet [9]. Eastern coals have a high fixed-carbon content and contain relatively low amounts of moisture and volatile matter. The sulfur content varies considerably, and approximately 65% of the identified resources have a sulfur content of more than 1%. Coal deposits are sometimes on the side of a hill or mountain; at other times they are buried deep below the surface. Seam thickness rarely exceeds six feet. The SERC region can also have access to the coal resources of the interior region. Most of this coal is also bituminous; but the sulfer content tends to be higher, generally in excess of 3% [8, 9, 10, 11].

Because of the uncertainties associated with foreign oil supply, increasing prices, and other factors, the role of oil-fired units in SERC will sharply decrease in the future. In the SERC region there are some potential oil discoveries in the Atlantic offshore and also in the Gulf Coast. But the total absolute potential is only about 40 billion barrels. The SERC region also has oil shale resources, mainly in the Appalachian region. Unfortunately these deposits are not presently regarded as economically recoverable, and most of them contain less than 10 gallons of oil per ton of shale.

Although the SERC region is the neighbor of the major gas producing states, gas has never been a major fuel for electric generation in any SERC subregion. Also with the new government regulations, gas is not expected to play any active role in the future SERC generating capacity.

As projected by the utilities, nuclear power will increase its capacity. But although break-even cost analysis shows nuclear power slightly more economical as base load generation, several factors such as uncertainty of nuclear fuel resources, safety, and environmental restrictions could limit nuclear development [10, 11].

Load Resources Analysis

This section discusses reserve margins, seasonal system load characteristics, probable system generation mix, and the specific role of hydropower.

Reserve Margin and System Reliability

Based on the utilities projections, the reserve margins are expected to remain above 20% for the next decade, except for the SOUTHERN subregion where the margin is projected at about 17% in 1990, and 14% in 1995. However, as discussed in the reserve margin of Chapter I, to provide adequate and reasonable power supply to meet the "median" peak demand, a minimum reserve of 17% and a maximum of 25% is applied to compute future generating capacities. Within this range, the reserve margin is based on the utilities projections, and is summarized in Table VII-2.

Table VII-2

RESERVE MARGINS
(Percent of Peak Demand)

Subregion	1985 %	1990 %	1995 %	2000 %
VACAR	25	21	18	17
TVA	25	22	22	22
SOUTHERN	20	17	17	17
FLORIDA	25	25	21	19

To enhance its system reliability, SERC participates in joint relability studies with its neighboring subregions. One of the purposes of these studies is to determine the power transfer capabilities between the systems for normal and contingency conditions, and to investigate operating procedures for any potential problems which may be indicated. In addition to these intraregional power exchanges, SERC has projected interregional emergency transfer capabilities for 1988 as shown in Table VII-3 [18].

Table VII-3

SERC
EMERGENCY TRANSFER CAPABILITIES
BETWEEN RELIABILITY COUNCILS (MW)
SUMMER 1988

From		To
SERC (VACAR)	4,550	MAAC
MAAC	3,750	SERC (VACAR)
SERC (TVA)	5,000	ECAR
ECAR	4,000	SERC (TVA)
SERC (VACAR)	5,500	ECAR
ECAR	3,600	SERC (VACAR)
SERC	1,700	SWPP
SWPP	2,000	SERC
SERC (TVA)	3,500	MAIN
MAIN	3,100	SERC (TVA)

Characteristics of Electric Loads

The weekly load curves for the first week of April, August, and December 1977 of representative utilities in SERC are presented in

Volume III, Exhibit VII-6. Table VII-4 presents a breakdown of these loads (base, intermediate, and peak) for each of these utilities as explained in Chapter I. These percentages are representative of each season. During each season, the loads may vary by several percent. The VACAR and TVA subregions have similar load distribution, both having a high annual base load of about 70% of their system peak. The SOUTHERN and FLORIDA subregions have higher peak load ranges, especially in summer due to a higher demand in air-conditioning.

Table VII-4

LOAD DISTRIBUTION IN SERC
(Percent of Annual Peak Load)

Subregion / Representative Utility	Base %	Intermediate %	Peak %
VACAR:			
Duke Power Company			
Off Season	55	20	9
Summer	66	20	12
Winter	70	18	12
Annual	70	18	12
TVA:			
Tennessee Valley Authority			
Off Season	60	10	8
Summer	62	14	9
Winter	70	20	10
Annual	70	20	10
SOUTHERN:			
Southern Companies System			
Off Season	46	14	5
Summer	60	22	18
Winter	57	15	10
Annual	60	22	18
FLORIDA:			
Florida Power & Light Company			
Off Season	38	24	10
Summer	60	18	18
Winter	58	24	18
Annual	60	22	18

From the load curves presented in Volume III, corresponding seasonal tabulations of energy are derived using the computer program described in Appendix A. These tabulations are presented in Exhibit VII-3 for each representative utility mentioned above. The use of this information for evaluating hydroelectric power potential is also discussed in Appendix A.

Generation Mix

This section presents future expansion plans. As discussed in Chapter I, an estimate of suggested generation mix for base, intermediate, and peaking capacities is evaluated for SERC. These evaluations are based on existing and planned generation facilities as reported by the utilities, characteristics of electric loads, an analysis of regional resource availability, economic parameters, Federal and state regulations, and other pertinent regional factors. To reflect the uncertainties and unforeseeable factors which can affect future generation mixes, a range of future installed capacity is defined for each major generation source. The projected future capabilities are based on the "median" demand, and the reserve margin presented in Table VII-2.

SERC Regional Summary. Table VII-5 shows the most probable generation mix to the year 2000 for SERC. In 1977, coal-fired units represented about 50% of the generating capacity in SERC. This percentage is expected to decrease over the next decade because there are not many coal-fired plants under planning or construction. But this trend could be reversed. More coal-fired plants could be planned and put into operation during the 1985-2000 period. By the year 2000, coal-fired units could again represent more than 50% of the generating capacity. Oil-fired units are expected to account for about 21% of the generating capacity up to year 1985. After that time, only a few units for peaking capacity would be added. The 2000 generation mix would probably not include more than 10% of the total generating capacity in oil-fired capacity. As planned by the utilities, nuclear is expected to increase rapidly from 15,000 MW in 1978 to about 45,000 MW in 1985. Although additional units are expected to be added in the following decade, the percentage is more likely to remain at about 25%. Other generation sources such as solar and wind, and other energy storage facilities such as compressed air and batteries could represent about 3% of the total generating capacity by the year 2000.

Table VII-5

SERC
GENERATION MIX
(Percent of Total Capability)

Generation Mix	1985	1990	1995	2000
	%	%	%	%
Base				
Nuclear	26-28	24-26	22-26	22-26
Coal	32-33	35-37	38-40	38-42
Oil	5-6	3-5	2-4	1-3
Conv. Hydro	0-1	0-1	0-1	0-1
Intermediate				
Coal 1/	10-12	11-13	14-16	15-18
Oil	7-8	6-8	5-7	4-6
Conv. Hydro	2-3	2-3	1-3	1-3
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	7-8	6-8	4-6	3-5
Conv. Hydro	3-4	3-4	2-4	2-4
Pumped Storage	3-4	3-4	2-4	2-4
Other	0	0-1	0-1	1-2
Total Capability (GW)	157.9	195.2	234.6	280.1

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

VACAR. Table VII-6 presents the future expected generation mix for VACAR. As planned by the utilities, nuclear is expected to increase rapidly. Although new units are expected to be added in the following decade, the percentage is more likely to remain between 30 and 35% of the total generating capacity. Because there are not many coal-fired plants under construction, the percentage of coal-fired capacity will decrease until 1985. More coal-fired plants could be planned and put

into operation after that date. Conventional installed hydropower had a capacity of 2,463 MW in 1977. If we consider that part of the hydropower potential at new identified sites, and at existing dams that could reasonably be developed, the hydropower could increase to about 4,000 MW by 2000. The utilities have projected a pumped-storage capacity of about 3,000 MW for 1985 and this capacity could increase to 5,000 MW by the year 2000.

Table VII-6

VACAR Subregion
GENERATION MIX
(Percent of Total Capability)

Generation Mix	1985	1990	1995	2000
	%	%	%	%
Base				
Nuclear	32-34	30-35	30-35	30-35
Coal	36-37	35-40	35-40	35-40
Conv. Hydro	0-1	0-1	0-1	0-1
Intermediate				
Coal 1/	6-8	8-10	10-12	10-12
Oil	8-10	6-8	5-8	4-8
Conv. Hydro	2-3	2-3	1-3	1-3
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	3-5	3-5	2-4	1-4
Conv. Hydro	2-3	2-3	2-3	2-3
Pumped Storage	6	5	4-6	3-6
Other	0	0-1	0-1	1-2
Total Capability (GW)	49.5	62.9	75.9	92.6

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

TVA Subregion Table VII-7 presents the probable TVA generation mix for the period 1985-2000. In 1977, nearly 65% of the generating capacity came from coal-fired units. Because no new coal plants are now under construction, this percentage will decrease sharply during the next decade. However, in the 1990's more coal-fired base-loaded steam plants will probably be constructed so that by the end of the century about half of the generating capacity could come from coal-fired units. The TVA oil-fired units are all combustion turbines. In 1977, they represented about 10% of the system generating capacity. As no new units are planned, this percentage will decrease and by the year 2000 the oil-fired capacity could be eliminated. Tennessee Valley Authority has planned an additional 15,700 MW of nuclear units to be in operation by 1985, representing about 93% of the total 1978-1985 additions. However, this trend in the expansion plans is not expected to continue because of economic, environmental, and other factors now tending to discourage nuclear facilities. By the year 2000, the nuclear capacity is expected to represent 35 to 40% of the total generating capacity. As mentioned in the above section there is a potential of about 500 MW in undeveloped conventional hydropower in the TVA subregion. Part of this potential could reasonably be developed, and some new units could be installed at existing dams. From 4,060 MW of hydropower capacity in 1977, TVA could reasonably be expected to continue because of economic, environmental, and other factors now tending to discourage nuclear facilities. By the year 2000, the nuclear capacity is expected to represent 35 to 40% of the total generating capacity. As mentioned in the above section there is a potential of about 500 MW in undeveloped conventional hydropower in the TVA subregion. Part of this potential could reasonably be developed, and some new units could be installed at existing dams. From 4,060 MW of hydropower capacity in 1977, TVA could reasonably be expected to increase to 5,000 MW by the end of the century. Although there is now only one pumped-storage project (Racoon Mountain, 1,530 MW) in the TVA subregion, the capacity could increase to 3,000 MW by the year 2000.

Table VII-7

TVA Subregion
GENERATION MIX
(Percent of Total Capability)

Generation Mix	1985	1990	1995	2000
	%	%	%	%
Base				
Nuclear	43-45	38-42	35-40	35-40
Coal	22-24	28-30	30-33	30-35
Conv. Hydro	1-2	1-2	1-2	0-1
Intermediate				
Coal 1/	15-17	16-18	18-20	18-20
Conv. Hydro	3-4	3-4	2-3	2-3
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	5-6	4-6	3-5	2-4
Conv. Hydro	4-5	3-4	3-4	2-3
Pumped Storage	3	2-4	2-4	2-4
Other	0	0-1	0-1	1-2
Total Capability (GW)	40.7	48.2	56.1	63.8

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

SOUTHERN Subregion. Table VII-8 presents the probable generation mix for the period 1985-2000. The SOUTHERN subregion relies primarily on coal to produce electrical energy. As discussed earlier, there are large coal reserves in this subregion. New coal-fired units are planned by the utilities, and the 1977 percentage of coal-fired generating capacity could increase slightly, perhaps reaching 70% by the end of the century. As in the other subregions, the percentage of

oil-fired generating capacity is expected to decrease, remaining below 5% after 1995. New nuclear plants are under construction and will increase the nuclear capacity to about 12% of the total 1985 generating capacity. Then new units are expected to be added to maintain the nuclear capacity percentage between 10 and 15% of the total system capacity. In 1977, there was a conventional hydropower capacity of 2,753 MW. Assuming that a third of the undeveloped potential could reasonably be developed, the conventional hydropower capacity could increase to 4,500 MW. There is a good potential for pumped-storage projects in the SOUTHERN subregion, and by the year 2000, the pumped-storage capacity could increase to 3,000 MW.

Table VII-8

SOUTHERN Subregion
GENERATION MIX
(Percent of Total Capability)

Generation Mix	1985	1990	1995	2000
	%	%	%	%
Base				
Nuclear	11-13	10-15	10-15	10-15
Coal	46-48	45-50	45-50	45-50
Conv. Hydro	1-2	1-2	0-1	0-1
Intermediate				
Coal 1/	18-20	18-20	18-20	20-22
Conv. Hydro	4-5	3-5	3-5	2-4
Other	0	0-1	0-1	0-1
Peaking				
Coal 1/	-	-	-	-
Oil	7-8	5-8	4-7	3-5
Conv. Hydro	4-5	4-5	3-5	3-5
Pumped Storage	4	3-4	2-4	2-5
Other	0	0-1	0-1	0-1
Total Capability (GW)	34.8	42.4	53.1	64.2

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

FLORIDA Subregion. Table VII-9 presents the probable generation mix for the period 1985-2000. Far from any coal mines, the FLORIDA subregion relies primarily on oil-fired units to provide electric energy. As discussed above in the Availability of Fuels this trend is expected to change. Even with transportation costs, coal becomes more and more attractive. New coal-fired units are being planned by the utilities and by the end of the century, coal may represent over 30% of FLORIDA's total generating capacity. Nuclear power is expected to represent about 10% to 15% of the total system generating capacity by the year 2000. Hydroelectric capacity is almost non existent in FLORIDA; the only conventional hydropower plant is Jim Woodruff, 30 MW. There is little potential for new hydropower, and in general, topography and geologic conditions are unsuitable for pumped-storage.

Table VII-9

FLORIDA Subregion
GENERATION MIX
(Percent of Total Capability)

Generation Mix	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	11-13	10-15	10-15	10-15
Coal	20-22	25-30	28-32	30-35
Oil	26-28	22-25	15-20	10-15
Intermediate				
Coal	-	0-5	0-5	0-5
Oil	20-22	18-20	18-20	18-20
Other	0	0-1	0-1	1-2
Peaking				
Oil	18-20	18-20	17-20	17-20
Other	0	0-1	1-2	1-3
Total Capability (GW)	32.9	41.7	49.4	59.5

Specific Role of Hydropower

Conventional Hydropower. As of December 1978, there was about 9,276 MW of an installed hydropower capacity, representing 9% of the total capability in SERC. The total electric energy generated by conventional hydropower was 31,200 million KWh or 7% of the total demand [19].

The TVA subregion has the highest conventional hydropower capacity. In that subregion hydropower capacity was about 4,300 MW in 1978, representing 16.5% of the total TVA installed capacity. The hydropower energy generated was about 17,000 million KWh, or 15% of the total demand. At this time, no new conventional hydropower plants are under construction. As a result, the percentage of hydropower energy will sharply decrease in the future, and is expected to represent only 9% of the "median" demand in 1988 [19].

The SOUTHERN subregion is the second largest user of hydropower in SERC. The conventional hydropower capacity of about 3,000 MW in 1978 generated 7% of the total energy demand in the SOUTHERN subregion Some new hydropower plants or additions are under construction, licensing or planning among which are Hartwell (80 MW), Mitchell (97 MW), Martin (55 MW), Wallace Dam (113 MW), Bartletts Ferry (100 MW), and Richard B. Russell (300 MW). Even with these additions, the hydropower energy is expected to represent only 5% of the "median" demand in 1988 [19].

The FLORIDA subregion does not have any significant hydropower capacity, and it will remain so in the future. The VACAR subregion has now a capacity of about 2,500 MW providing 7,000 million KWh in 1978 [5% of the total demand]. Although there are two new hydropower plants under construction (St. Stephen Hydro, and a share of Richard B. Russel), the hydropower capacity percentage will decrease. The hydropower energy is expected to represent about 2.5% of the demand in 1988 [19].

As shown in Table VII-1, there is a large potential at undeveloped sites and existing dams. Part of it could be developed. Based on each site's characteristics, environmental constraints, and other parameters, the energy would be best used for intermediate and peaking demand to displace as much oil as possible.

<u>Pumped Storage</u>. As of December 1978, there was an installed capacity of about 1,600 MW of pumped storage, representing 1.5% of the total capability in SERC. The energy output was about 1,000 million KWh, or 0.2% of the total demand. This percentage is expected to increase to about 1% due to the new units under construction at Carters (250 MW), Wallace Dam (212 MW), Rocky Mountain (675 MW) in the SOUTHERN subregion, Racoon Mountain (1,300 MW) in TVA, and Bath County (2,100 MW) in VACAR. The Russell project in the SOUTHERN subregion has 300 MW of pump-back capacity authorized for construction. With large nuclear and coal-fired plants providing low-cost base energy, pumped

storage becomes more and more attractive to reduce the dependence on oil to provide peaking capacity and energy.

Sensitivity Analysis

The projections of future electric demand and supply presented in this chapter are based on numerous factors, each of which is sensitive to public opinion, economics of energy use, and changes in domestic or international policies. The number of variations that could be analyzed is nearly infinite. However, regardless of variations in items, population reflects the ultimate energy use. Of particular importance are variations in projected population growth rates. Such variations will directly affect Projections II and III, since they are based upon per capita energy consumption. Projection I would be indirectly affected as it is based on an aggregation of utility forecasts, each of which may have a different underlying forecast methodolgy. Changes in projected economic growth, rate of implementation of conservation measures, Federal and state regulations, and other regional factors are difficult to gauge but will no doubt affect all of the projections. A general discussion of projection sensitivity is presented in Appendix C.

Changes in the regional population growth rates would definitely affect Projections II and III, and, most likely, the "median" projection. The following table indicates what effects, if any, selected changes in population growth rates would have on the median projection of electric energy consumption in SERC.

Percent Change in Population Growth Rates	Percent Change in Energy Demand of Projections II & III in the Year 2000	1/ "New" Median Enegy Demand (GWh)
-50	-12.9	1147.4
-15	- 4.1	1203.0
0	0	1233.0
+15	+ 4.2	1274.4
+50	+14.9	1358.7

1/ Median energy demand is computed as the median of Projection I (unchanged) and Projections II and III (adjusted as indicated).

As discussed earlier, some of the boundaries of SERC, particularly in the VACAR subregion, are not readily matched by the boundaries of the appropriate BEA areas. In the case of VACAR, the Washington D.C. area is served by Potomac Electric Power Company which is actually part of the MAAC region; however, its population is considered to be part of the VACAR population. The affect of this is that the VACAR population is reported a bit higher than it should be. This population difference does not affect the magnitude of the power and energy projections. It only affects the per capita consumption data.

In SERC as well as throughout the country, electric-energy conservation measures and load-management measures will most likely be employed in an attempt to offset rising energy prices regardless of other economic activity. Large-scale adoption of conservation will have an effect on electric generation requirements similar to that of depressed economic conditions in that projected demand for both electric power and energy would be reduced. However, conservation will not impede hydroelectric generation, but rather will point to its value and its contribution to conservation. More likely than not, planned thermal-electric generation will be curtailed.

Conversely, if economic activity were to exceed expectations, future demand for energy might exceed the median projection. However, conservation and load-control measures could relieve the capacity situation somewhat, so that electric-energy use would increase to a larger degree than would capacity requirement. Under such circumstance, hydroelectric power and energy would provide operating economy and there would be demand for all that could be economically installed.

To summarize, electric capacity and energy demand could vary widely from the projections, but the overall need for national energy conservation will continue to justify the production of hydroelectric energy.

Chapter VIII

SOUTHWEST POWER POOL
FUTURE ELECTRIC POWER DEMAND AND SUPPLY

Introduction

This chapter presents future electric demands and power resources in the Southwest Power Pool (SWPP) and assesses potential for utilization of new hydropower resources. The assessment includes fixed-factors projection of variable factors to the year 2000, among which are the following:

1. Population and economic growth,
2. Electric power and energy demand,
3. Hydropower potential,
4. Availability of fuel resources,
5. Characteristics of electric loads,
6. Generation mix by type of fuel, and
7. Hydropower utilization.

The underlying assumption and methodology of the projections presented in this chapter are described in Chapter I. In addition, in depth discussions of load curves, attractiveness of hydropower, and projection sensitivity are presented in Appendices A, B, and C respectively. The combination of Chapter I, this chapter, and the appendices summarizes the future electric energy demand and supply and the potential role of hydropower in the SWPP region.

The SWPP boundaries are shown on Exhibit I-1. The SWPP region includes all of the states of Arkansas, Kansas, Louisiana and Oklahoma, and part of the states of Mississippi, Missouri, New Mexico and Texas. In this study, SWPP's considered as one study region; there is no division into subregions.

An overview of the electrical situation with emphasis on the role of hydropower in SWPP for 1978 is discussed in Chapter VIII of Volume III. Included in Volume III are a description of power systems which are bulk power suppliers in SWPP, an analysis of regional electric-power demand and supply and a load resource balance. The area covered by the SWPP region is shown on the national map on Exhibit I-1.

Demographic and Economic Growth

Exhibit VIII-1 summarizes the significant demographic and economic projections for 1980, 1985, 1990, and 2000. The demographic and

economic data are for the study region as approximated by the selected BEA economic areas discussed in Chapter I. The list of BEA areas comprising the region is presented in Exhibit I-2. The projections are based on the 1972 OBERS projections [1].1/

SWPP had about 7.2 percent of the total U.S. population and about 6.0 percent of the U.S. total personal income in 1970. The share of national population and income in SWPP has decreased since then and is expected to continue decreasing through 2000.

The projected population growth rate is expected to be about 0.4 percent between 1970 and 2000, significantly lower than the historical growth rate of 0.7 percent from 1950 to 1970. The projected population growth rate is also much lower than that projected for the nation.

Earnings and total personal income in the SWPP area are expected to grow at an average annual rate of 3.3 percent, just slightly lower than the national average. The manufacturing sector is expected to exceed earnings in the services, trade, and government sector. It should be noted that agriculture and mining are important in SWPP in that they contribute to large percentages of national sector earnings in these sectors.

Per capita income in SWPP has historically (1950-1970) been lower than the national average, although the difference has been decreasing with respect to time. The disparity between SWPP and national per capita income is expected to continue to decrease. The projected average annual growth rate of SWPP per capita income between 1970 and 2000 is about 2.9 percent, slightly lower than the historical growth rate (1950-1970) of 3.1 percent.

Future Electric Power Demand

As discussed in Chapter I, three projections of electricity demand are developed for use in assessing the regional market for hydropower [4,5,30]. From these, the "median" projection is selected. The OBERS population projections are adjusted to reflect the latest census data [2] as described in Chapter I. The future electric-power demand and adjusted population projections for SWPP are shown on Exhibit VIII-2.

1/ Numbers in brackets refer to references which immediately follow Chapter XII.

Energy Demand

The annual electric-energy consumption in SWPP is expected to grow from 191.6 thousand GWh in 1978 to about 277.6 thousand GWh in 1985, representing a compounded growth rate of 5.4% annually. Growth in energy demand is expected to continue at about 4.6% annually until 1990, resulting in an energy demand of 348.0 thousand GWh. From 1990 to 2000 the growth rate in electrical-energy consumption is expected to slow to about 3.7 percent. The "median" energy demand for the year 2000 is 498.7 thousand GWh, representing an average compound and annual rate of 4.4% between 1978 and 2000.

Peak Demand

Presently SWPP is a summer peaking region and is expected to remain so in the future. In 1978 the summer peak was 39.191 MW, and the winter peak was 28,350 MW. The "median" peak is expected to grow at 5.2% annually between 1978 and 1985. After 1985, growth in peak demand is expected to closely follow growth in energy demand. The "median" peak demand is projected to be 56,000 MW in 1985, and about 100,000 MW in 2000.

Load Factor

SWPP had an annual load factor of 55.8% in 1978. From the projected peak and energy demands forecast by the utilities, future annual load factors are expected to vary between 56.6% and 57.0% [30]. As explained in Chapter I, these load factors are assumed to remain constant for the period 1990-2000. Within SWPP, utilities have annual load factors varying between 45 and 70% (Exhibit VIII-5 of Volume 10).

Estimate of Electric Power Supply

This section discusses major sources of electric power supply to be considered in developing future expansion plans for power capacity additions in SWPP. The hydropower potential is presented, followed by a discussion on the regional fuel availability.

Hydropower Potential

The data in this section is based on earlier reports and is only used in this volume to provide an indication of the regional hydroelectric power potential. The data is principally used in developing the future generation mix. More definitive information on hydropower potential is contained in the regional report on SWPP.

Table VIII-1 summarizes SWPP hydropower potential at existing dams and undeveloped sites. Hydropower at undeveloped sites is as identified by the Federal Power Commission (now FERC) in 1976 [6]. The identified sites are restricted to those with potential installed capacity of greater than 5 MW. Hydropower potential at existing dams is as estimated by the U.S. Army Corps of Engineers, Institute for Water Resources (IWR) in July 1977 [7]. The IWR estimate of potential at existing dams is unrestricted with respect to size, and includes dams with a potential installed capacity of less than 5 MW. In 1978, the total installed hydroelectric capacity in SWPP was about 2,440 MW, and the energy production was 5.2 million MWh.

Table VIII-1

SWPP

UNDEVELOPED HYDROPOWER POTENTIAL

	Potential Installed Capacity (MW)	Average Annual Energy (1000 MWH)
Potential at Undeveloped sites (greater than 5 MW)	1,670	3,880
Potential at Existing Dams	5,910	16,900
Total Potential	7,580	20,780

Undeveloped sites with significant potential are primarily in Oklahoma and Arkansas and the main potential developments are on the Little, Kiamichi, Ouachita, and White Rivers. These two states have a potential of about 1,250 MW, with an average annual generation of 2,200 GWh at undeveloped sites.

The U.S. Army Corps of Engineers has surveyed the national potential for additional hydropower at existing dams. This survey includes numerous small existing dams, and 85% of the total potential of 5,910 MW could come from dams with a potential capacity of less than 5 MW.

Availability of Fuels

SWPP is located close to the uranium producing regions of Wyoming, New Mexico, Texas, and Colorado. The proximity to these uranium producing regions is not a prerequisite for nuclear development, but it may be an encouraging factor. Water resources required for thermal powerplant development are located primarily in the eastern half of the region [8,9,12,13].

Most of the coal in the region has a high sulfur content, generally in excess of 3%. Although the coal reserves in the area amount to about 40 billion tons of bituminous coal, it is expected that most of the coal consumed in the area would be imported from Western States. Coal-slurry pipelines could bring coal from the Montana-Wyoming area. There are some small deposits of lignite coal in Arkansas.

Natural gas and oil resources are comparatively abundant in the area; Louisiana, Oklahoma, and Kansas are among the largest gas and oil-producing states in the country. Presently, the SWPP generation mix is heavily dependent upon natural gas. However, future natural gas production is not expected to increase, and oil prices are rising rapidly. As shown later in this chapter, this situation will most likely result in a shift from use of the fuels for electric power generation to a more economical fuel-coal.

Shale oil and tar sand deposits are dispersed throughout the SWPP region. However, none of the known deposits in the region are, now, large enough to produce significant amounts of fuel for electric power generation.

Load Resources Analysis

This section discusses reserve margins, seasonal system load characteristics, probable system generation mix, and the specific role of hydroelectric power in the SWPP region.

Reserve Margin and System Reliability

The currently-approved SWPP Planning Criteria (now undergoing review) provides that total generating capacity shall be such that the capacity available shall exceed the predicted annual peak load obligation by a margin of 15 percent. As an alternative, generating capability should be sufficient to insure that the probability of load exceeding available capacity shall not be greater than one occurrence

in ten years. However, in no case shall the reserve be less than 12% of the peak load obligation.

Based on the utilities projections, the reserve margin is projected at about 20% through 1985, and about 18% until 2000. Although there are adequate reserve margins throughout the forecast period, timely installation of nuclear and large fossil units is crucial.

To provide mutual assistance during emergency conditions, it is expected that emergency transfer capabilities for 1988 as projected by the NERC regions will be as shown in Table VIII-2 [18].

Table VIII-2

SWPP
EMERGENCY TRANSFER CAPABILITIES
BETWEEN RELIABILITY COUNCILS (MW)
SUMMER 1988

From		To
SWPP	1,000	MARCA
MARCA	1,000	SWPP
SWPP	1,600	MAIN
MAIN	600	SWPP
SWPP	2,000	SERC
SERC	1,700	SWPP

There is transfer capability between SWPP and ERCOT, but normally it is not used.

Characteristics of Electric Loads

The weekly load curves for the first week of April, August, and December 1977 of representative utilities in SWPP are presented in Volume III, Exhibit VIII-6. Table VIII-3 presents a breakdown of these loads (base, intermediate, and peak) for each of these utilities as explained in Chapter I. These percentages are representative of each season. However, during each season, the load distributions as shown, may vary by several percent.

Except for Gulf States Utilities Company, the annual base load of the representative utilities varies between 56 and 58%, and the peak

load varies between 16 and 18%, of the peak annual demand. As shown in Table VIII-2, Gulf States Utilities Company has a much higher base load in summer. The portions of the load considered as base, intermediate, and peak are the basis for deriving the generation mix.

From the load curves presented in Volume III, corresponding seasonal tabulations of energy are derived using the computer program described in Appendix A. These tabulations are presented in Exhibit VIII-3 for each of the representative utilities mentioned above. The use of this information for evaluating hydroelectric power potential is also discussed in Appendix A.

Generation Mix

This section presents future expansion plans. As discussed in Chapter I, an estimation of suggested generation mix for base, intermediate, and peaking capacities is evaluated for SWPP. This evaluation is based on existing and planned generation facilities as reported by the utilities, characteristics of system loads, an analysis of regional resources availability, economic parameters, Federal and state regulations, and other pertinent regional factors. However, to reflect the uncertainties and unforseeable factors which can affect future generation mixes, a range of future installed capacity is defined for each major generation source. The future capabilities are based on the "median" demand and the reserve margins as previously discussed.

SWPP Regional Summary. Table VIII-4 shows the most probable generation mix to the year 2000 for SWPP. At present, SWPP is highly dependent on natural gas and oil as a boiler fuel, which supplies about 75% of the electric energy requirements of the region. The nuclear and coal-fired generating capacity additions planned by the utilities is an attempt by SWPP utilities to reduce their reliance on natural gas and oil. Recent conversation with SWPP has indicated that exchanges of capacity and energy between utilities are reducing their dependence on oil. At the same time, Federal regulatory constraints have impeded greater use of natural gas. Between 1985 and 2000, additions to generating capability are likely to be nuclear, coal, and a limited amount of hydroelectric capacity. Gas and oil generating capability will decrease as existing plants are retired, and older plants will be used to meet intermediate and peak loads. Other sources such as wind, solar, biomass, peat, and geothermal are not expected to provide more than 1 or 2% of SWPP intermediate or peak capacity by year 2000.

Table VIII-3

LOAD DISTRIBUTION IN SWPP
(Percent of Annual Peak Load)

Representative Utilities:	Base %	Intermediate %	Peak %
Gulf States Utilities Company			
Off Season	57	5	5
Summer	77	13	10
Winter	63	4	6
Annual	77	13	10
Oklahoma Gas & Electric Company			
Off Season	37	10	5
Summer	56	26	18
Winter	50	10	7
Annual	56	26	18
Southwestern Electric Power Company			
Off Season	34	11	5
Summer	58	24	18
Winter	44	11	7
Annual	57	25	18
Kansas City Power & Light Company			
Off Season	39	6	5
Summer	56	24	20
Winter	45	13	6
Annual	56	24	20

Specific Role of Hydropower

Conventional Hydropower. As of December 31, 1978, there was an installed generating capability of about 2,440 MW of conventional hydropower, representing 5.2% of the total generating capability in SWPP. The total electric energy generated by conventional hydropower was 5,185 million kWh in 1978, representing 2.7% of the total energy [19]. As reported by the utilities in the SWPP report [30], there is only one addition planned for the next decade, the 27 MW Clarence Cannon plant now under construction. As a result, conventional hydropower will account for decreasing portions of the total system capability. In 1988, hydropower energy is expected to account for only 1.7% of the "median" demand.

As shown in Table VIII-1, there is large potential for hydroelectric development in SWPP. Many existing dams with a potential capacity of less than 5 MW could be developed. Although dependent on environmental constraints, the energy produced would best serve the system it used for intermediate and peaking loads since it would reduce the use of oil.

Pumped Storage. As of December 31, 1978 SWPP had an installed generating capacity of 260 MW of hydroelectric pumped storage, with an annual output of 244 million kWh [19], representing 0.1% of the total energy generated. The six Truman units (160 MW), and the Clarence Cannon Unit (31 MW) are under construction,and will increase the pumped-storage capacity to a total of 451 MW by 1981. In addition, the De Gray project should have 28 MW of reversible capacity. Although the energy available from hydroelectric pumped-storage will remain negligible during the next decade, there could be a large market potential for underground or conventional pumped-storage peaking plans when suitable sites can be found. Because of the low-cost off peak thermal energy that could be provided by the large, new nuclear and coal-fired steam plants, pumped-storage capacity could be as much as 3% of the total installed capacity by year 2000. This would further reduce SWPP's dependence on oil and gas.

Sensitivity Analysis

The projections of future electric demand and supply presented in this chapter are based on numerous factors, each of which is sensitive to public opinion, economics of energy use, and changes in domestic or international policies. The number of variations that could be analyzed is nearly infinite. However, regardless of variations in items, population reflects the ultimate energy use. Of particular importance

Table VIII-4

SWPP
GENERATION MIX
(Percent of Total Capability)

Generation Mix	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	10-12	10-12	11-13	12-15
Coal	24-26	30-32	32-35	36-40
Gas	22-24	18-20	13-16	10-12
Intermediate				
Coal 1/	8-10	10-12	11-13	13-15
Oil	4-6	3-5	2-4	2-4
Gas	8-10	8-10	7-9	6-9
Conv. Hydro	1-2	1-2	1-2	1-2
Other	0	0-1	0-1	1-2
Peak				
Coal 1/	-	-	-	-
Oil	6-8	5-7	3-5	2-3
Gas	7-8	7-8	6-8	4-8
Conv. Hydro	2-3	1-2	1-2	1-2
Pumped Storage	0.7	0.5	0-1	0-3
Other	0	0-1	0-1	1-2
Total Capability (GW)	66.6	82.5	97.9	118.3

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

are variations in projected population growth rates. Such variations will directly affect Projections II and III, since they are based upon per capita energy consumption. Projection I would be indirectly affected as it is based on an aggregation of utility forecasts, each of which may have a different underlying forecast methodolgy. Changes in projected economic growth, rate of implementation of conservation measures, Federal and state regulations, and other regional factors are difficult to gauge but will no doubt affect all of the projections. A general discussion of projection sensitivity is presented in Appendix C.

Changes in the regional population growth rates would definitely affect Projections II and III, and, most likely, the "median" projection. The following table indicates what effects, if any, selected changes in population growth rates would have on the median projection of electric energy consumption in SWPP.

Percent Change in Population Growth Rates	Percent Change in Energy Demand of Projections II & III in the Year 2000	"New" Median Enegy Demand (GWh) 1/
-50	-6.4	466.8
-15	-2.0	488.9
0	0	498.7
+15	+2.0	508.7
+50	+6.8	532.7

1/ Median energy demand is computed as the median of Projection I (unchanged) and Projections II and III (adjusted as indicated)

In SWPP as well as throughout the country, electric energy conservation measures and load-management measures will most likely be employed in an attempt to offset rising energy prices regardless of other economic activity. Large-scale adoption of conservation will have an effect on electric generation requirements similar to that of depressed economic conditions in that projected demand for both electric power and energy would be reduced. However, conservation will not impede hydroelectric generation, but rather will point to its value and its contribution to conservation. More likely than not, planned thermal-electric generation will be curtailed.

Conversely, if economic activity were to exceed expectations, future demand for energy might exceed the median projection. However,

conservation and load-control measures could relieve the capacity situation somewhat, so that electric energy use would increase to a larger degree than would capacity requirement. Under such circumstance, hydroelectric power and energy would provide operating economy and there would be demand for all that could be economically installed.

To summarize, electric capacity and energy demand could vary widely from the projections, but the overall need for national energy conservation will continue to justify the production of hydroelectric energy.

Chapter IX

ELECTRIC RELIABILITY COUNCIL OF TEXAS
FUTURE ELECTRIC POWER DEMAND AND SUPPLY

Introduction

This chapter presents future electric demands and power resources in the Electric Reliability Council of Texas (ERCOT) and assesses potential for utilization of new hydropower resources. The assessment includes fixed factors and projection of variable factors to the year 2000, among which are the following:

1. Population and economic growth,
2. Electric power and energy demand,
3. Hydropower potential,
4. Availability of fuel resources,
5. Characteristics of electric loads,
6. Generation mix by type of fuel, and
7. Hydropower utilization.

The underlying assumption and methodology of the projections presented in this chapter are described in Chapter I. In addition, in-depth discussions of load curves, attractiveness of hydropower, and projection sensitivity are presented in Appendices A, B, and C respectively. The combination of Chapter I, this chapter, and the appendices, summarizes the future electric-energy demand and supply and the potential role of hydropower, in the ERCOT region.

The ERCOT region includes most of the State of Texas. The area is approximately 195,000 square miles. An overview of the electrical situation with emphasis on the role of hydropower in ERCOT for 1978 is discussed in Chapter IX of the Volume III. Included in that volume, are a description of power systems which are bulk power suppliers in ERCOT, an analysis of regional electric-power demand and supply, and a load resource balance. The map of the region is shown on the national map in Exhibit I-1.

Demographic and Economic Growth

Exhibit IX-1 summarizes the significant demographic and economic projections for ERCOT as approximated by the selected BEA economic areas discussed in Chapter I. A list of the BEA areas is presented in

Exhibit I-2. The projections are based on the 1972 OBERS projections [1].[1/]

The population of the area is expected to grow at the average rate of about 0.8 percent between 1970 and 2000, slightly higher than the projected national rate of about 0.7 percent. Between 1950 and 1970 the per capita income in ERCOT was slightly lower than the national average, and is expected to remain so, growing at an average annual rate of 2.8 percent from 1970 through 2000.

During 1970 earnings in the trade, government, and manufacturing sector accounted for the largest portions of total earnings in ERCOT, and are expected to remain important until 2000. The services sector is expected to grow and produce the largest portion of earnings in the ERCOT by 2000. Overall, total earnings in ERCOT are expected to grow at the average annual rate of 3.5 percent, slightly higher than the national average.

Future Electric Power Demand

As discussed in Chapter I, three projections of electricity demand are developed for use in assessing the regional market for hydropower [4,5,31]. From these, the "median" projection is selected. The OBERS population forecasts are adjusted to reflect the latest census [2] as described in Chapter I. The future electricity demands, and adjusted population projections for ERCOT are shown in Exhibit IX-2.

Energy Demand

The future annual "median" electric energy consumption in ERCOT is expected to grow from 147,400 GWh in 1978 to 206,200 GWh in 1985, representing a compound annual growth rate of 4.9%. By the year 2000, electric energy consumption is expected to grow to about 409,700 GWh, representing a compound annual rate of 4.8% between 1978 and 2000.

Peak Demand

Presently, ERCOT is a summer peaking region and is expected to remain so in the future. In 1978, the summer peak was equal to 28,645 MW. The peak is expected to increase to 41,300 MW in 1985 and 82,200

1/ Numbers in brackets refer to references which immediately follow Chapter XII.

MW in year 2000, representing an average annual growth rate of 4.8% over the period 1978 2000.

Load Factor

In 1978, ERCOT had an annual load factor of 58.8%. From the projected peak and energy demands forecast by the utilities, future annual load factors for ERCOT are expected to average 57%.

Estimate of Electric Power Supply

This section discusses major sources of electric power supply to be considered in developing future expansion plans for power capacity additions in ERCOT. The hydropower potential is presented, followed by a discussion on the regional fuel availability.

Hydropower Potential

The data in this section is based on earlier reports and is only used in this volume to provide an indication of the regional hydroelectric power potential. The data is principally used in developing the future generation mix. More definitive information on hydropower potential is contained in the regional report on ERCOT.

Table IX-1 summarizes the hydropower potential. Hydropower at undeveloped sites is as identified by the Federal Power Commission (now FERC) in 1976 [6]. The identified sites are restricted to those with potential installed capacity greater than 5 MW. Hydropower potential at existing dams is as estimated by the U.S. Army Corps of Engineers, Institute for Water Resources (IWR) in July 1977 [7]. The IWR estimate of potential at existing dams is unrestricted with respect to size, and includes dams with a potential installed capacity of less than 5 MW. In 1978, the total installed hydroelectric capacity was about 230 MW, and the energy production was 288 GWh.

Availability of Fuels

Uranium extractions in the State of Texas are expected to grow from one thousand tons in 1976 to 4.4 thousand tons by 2000. The State of Texas was fourth in the production of uranium during 1976 and is expected to remain so through 2000. The availability of uranimum in the State will likely contribute to the development of ERCOT's nuclear power capacity [8,9].

Table IX-1

ERCOT
UNDEVELOPED HYDROPOWER POTENTIAL

	Potential Installed Capacity (MW)	Average Annual Energy (1000 MWh)
Potential at Undeveloped Sites (greater than 5 MW)	1,070	1,570
Potential at Existing Dams	750	1,880
Total Potential	1,820	3,450

ERCOT has little total area that is densely populated or on reserved public land status; thus, land resources in ERCOT impose few restrictions on the siting of nuclear or other forms of generation. Availability of fresh water runoff is limited, however. The ERCOT region averages only 3.5 inches of surface water runoff annually, with runoff being extremely flashy. The limited availability of fresh water may be a determining factor in selecting alternative generation methods.

Coal resources in the ERCOT region are limited. In 1978, Texas had an estimated reserve of 6,000 million tons of bituminous coal and 10,000 million tons of lignite coal [8,9]. The bituminous coal is located primarily in the center of the State, and the lignite is dispersed throughout the east central portion of the State. Most of the coal has a sulfur content between 1.1 and 3.0 percent and is strip mined. Two coal-slurry pipelines are expected to be in operation by the year 2000. One pipeline may extend from the bituminous coal fields in central Colorado to the Gulf of Mexico. The other pipeline may extend from eastern Montana to the Gulf of Mexico.

The State of Texas is the largest producer of oil in the U.S. However, ERCOT utilities have few oil-fired generating facilities, and are not dependent upon oil for electric power generation.

Natural gas production in Texas during 1976 was 4.2 trillion cubic feet, the largest in the Nation. This large production of natural gas is largely a result of natural abundance and the ERCOT utilities dependend to a major extent on the resource. However, the national energy plan requires a shift from dependence on natural gas to other sources. Therefore, the use of natural gas for electric generation in the State will decline in the future.

Load Resources Analysis

This section discusses reserve margins, seasonal system load characteristics, probable system generation mix, and the specific role of hydroelectric power.

Reserve Margin and System Reliability

As projected by the utilities, the reserve margin for ERCOT is expected to decrease from over 30% in 1978 to about 25% in 1985, and to approximately 15% by 2000. However, as discussed in Chapter I, to provide adequate and reasonable power supply to meet the "median" peak demand, a minimum reserve of 17% and a maximum of 25% is applied to compute future generating capacities. Within this range, the reserve margin is based on the utilities projections, and is presented in Exhibit IX-2.

Before 1977, ERCOT consisted of two interconnected groups. Since then, ERCOT has continued to operate on an intrastate basis with no operating interconnections to other regional groups. It is expected to continue so in the near future, at least.

Characteristics of Electric Loads

The weekly load curves for the first week of April, August, and December 1977 of representative utilities in ERCOT are presented in Volume III, Exhibit IV-6. Table IX-2 presents a breakdown of these loads (base, intermediate, and peak) for Houston Lighting & Power Company as explained in Chapter I. These percentages are representative of each season. During each season, the loads may vary by several percent.

From the load curves presented in Volume III, corresponding seasonal tabulations of energy are derived using the computer program described in Appendix A. These tabulations are presented in Exhibit IX-3 for Houston Lighting & Power Company. The use of this information for evaluating hydroelectric power potential is also discussed in Appendix A.

Table IX-2

LOAD DISTRIBUTION IN ERCOT
(Percent of Annual Peak Load)

Representative Utility:	Base %	Intermediate %	Peak %
Houston Lighting & Power Company			
Off Season	50	8	6
Summer	71	16	13
Winter	55	6	7
Annual	71	16	13

Generation Mix

This section presents future expansion plans. As discussed in Chapter I, an estimate of suggested generation mix for base, intermediate, and peaking capacities is evaluated for ERCOT. These evaluations are based on existing and planned generation facilities as reported by the utilities, characteristics of electric loads, an analysis of regional resource availability, economic parameters, Federal and state regulations, and other pertinent regional factors. To reflect the uncertainties and unforeseeable factors which can affect future generation mixes, a range of future installed capacity is defined for each major generation source. The projected future capabilities are based on the "median" demand, and the reserve margins presented in Exhibit IX-2.

ERCOT Regional Summary. Table IX-3 presents the most probable generation mix in ERCOT to the year 2000. ERCOT is presently installing large nuclear and coal-fired plants. The first nuclear plant is expected to start operating in 1981 or 1982. In 1985, nuclear capacity is expected to represent more than 10% of the total capacity. After that, nuclear capacity is expected to stabilize at about 12-16% of the total installed capacity. Coal-fired capacity will slowly increase, and could reach 40% by year 2000. Gas will continue to play an important role, especially to meet the intermediate and peak loads.

Table IX-3

ERCOT
GENERATION MIX
(Percent of Total Capability)

Generation Mix	1985	1990	1995	2000
	%	%	%	%
Base				
Nuclear	10-12	12-14	12-14	12-16
Coal	27-29	30-33	32-35	35-40
Gas	33-35	30-32	25-28	20-25
Intermediate				
Gas	15-17	15-17	15-17	14-17
Other	0	0-1	0-1	1-2
Peaking				
Gas	13-15	13-15	13-15	12-15
Oil	0-1	0-1	0-1	0-1
Conv. Hydro	0-1	0-1	0-1	0-1
Pumped Storage	0	0	0	0-1
Other	0	0-1	0-1	1-2
Total Capability (GW)	51.6	61.8	77.0	96.2

Specific Role of Hydropower

Conventional Hydropower. As of December 1978, there was an installed capacity of about 230 MW of conventional hydropower, with mean annual generation of 288 million kWh [19]. As shown in Table IX-1, hydroelectric potential exists in ERCOT, but is limited in magnitude. At present, there is only one hydropower plant being planned which is Amistad with a capacity of 32 MW. As a result, future energy produced by conventional hydropower which represented only 0.2% of the total energy demand in 1978, will reduce as a percentage of the total generation.

Pumped Storage. At the present time, the only pumped storage is at Buchanan on the Colorado River. However, records indicate that it

has principally been used for conventional hydroelectric generation; the pumping capability is seldom if ever used. This situation is caused by the large-scale use of gas base load generation, which does not provide the economic incentives to compensate for the cost of pumping energy. As coal and nuclear come into increasing use, pumped storage may become attractive. Texas has few sites favorable for pumped storage topographically or geologically. However, rivers on which there is a succession of reservoirs may accommodate pumped storage. No pumped storage is listed in present expansion plans.

Sensitivity Analysis

The projections of future electric demand and supply presented in this chapter are based on numerous factors, each of which is sensitive to public opinion, economics of energy use, and changes in domestic or international policies. The number of variations that could be analyzed is nearly infinite. However, regardless of variations in items, population reflects the ultimate energy use. Of particular importance are variations in projected population growth rates. Such variations will directly affect Projections II and III, since they are based upon per capita energy consumption. Projection I would be indirectly affected as it is based on an aggregation of utility forecasts, each of which may have a different underlying forecast methodolgy. Changes in projected economic growth, rate of implementation of conservation measures, Federal and state regulations, and other regional factors are difficult to gauge but will no doubt affect all of the projections. A general discussion of projection sensitivity is presented in Appendix C.

Changes in the regional population growth rates would definitely affect Projections II and III, and, most likely, the "median" projection. The following table indicates what effects, if any, selected changes in population growth rates would have on the median projection of electric energy consumption in ERCOT.

Percent Change in Population Growth Rates	Percent Change in Energy Demand of Projections II & III in the Year 2000	"New" Median Enegy Demand (GWh) 1/
-50	-11.5	379.7
-15	- 3.6	409.7
0	0	409.7
+15	+ 3.7	409.7
+50	+12.8	409.7

1/ Median energy demand is computed as the median of Projection I (unchanged) and Projections II and III (adjusted as indicated).

In ERCOT as well as throughout the country, electric energy conservation measures and load-management measures will most likely be employed in an attempt to offset rising energy prices regardless of other economic activity. Large-scale adoption of conservation will have an effect on electric generation requirements similar to that of depressed economic conditions in that projected demand for both electric power and energy would be reduced. However, conservation will not impede hydroelectric generation, but rather will point to its value and its contribution to conservation. More likely than not, planned thermal-electric generation will be curtailed.

Conversely, if economic activity were to exceed expectations, future demand for energy might exceed the median projection. However, conservation and load-control measures could relieve the capacity situation somewhat, so that electric energy use would increase to a larger degree than would capacity requirement. Under such circumstance, hydroelectric power and energy would provide operating economy and there would be demand for all that could be economically installed.

To summarize, electric capacity and energy demand could vary widely from the projections, but the overall need for national energy conservation will continue to justify the production of hydroelectric energy.

Chapter X

WESTERN SYSTEMS COORDINATING COUNCIL
FUTURE ELECTRIC POWER DEMAND AND SUPPLY

Introduction

This chapter presents future electric demands and power resources in the Western System Coordinating Council (WSCC) and assesses potential for utilization of new hydropower resources. The assessment includes fixed factors and projection of variable factors to the year 2000, among which are the following:

1. Population and economic growth,
2. Electric power and energy demand,
3. Hydropower potential,
4. Availability of fuel resources,
5. Characteristics of electric loads,
6. Generation mix by type of fuel, and
7. Hydropower utilization.

The underlying assumptions and methodology of the projections presented in this chapter are described in Chapter I. In addition, in depth discussions of load curves, attractiveness of hydropower, and projection sensitivity are presented in Appendices A, B, and C respectively. The combination of Chapter I, this chapter, and the appendices summarizes the future electric-energy demand and supply and the potential role of hydropower in the WSCC region.

The WSCC area covers approximately 16 million square miles, a little less than half of the total contiguous land area of the U.S. The members of WSCC are grouped into three geographical subregions:

1. The Arizona-New Mexico Power Area,
2. The Northwest Power Pool Area,
3. The Rocky Mountain Power Area,
4. The Northern California-Nevada Power Area, and
5. The Southern California-Nevada Power Area.

An overview of the electrical situation, with emphasis on the role of hydropower, in WSCC for 1978 is discussed in Chapter X of Volume III. Included in that volume are a description of power systems which are bulk power suppliers in WSCC, an analysis of the existing regional

electrical-power demand and supply, and a load resource balance. A map of the WSCC region is shown on the national map on Exhibit I-1.

Demographic and Economic Growth

Sheet 1 of Exhibit X-1 summarizes the significant demographic and economic projections for WSCC; Sheets 2 through 6 summarize the projections for the five subregion as approximated by the selected BEA economic areas discussed in Chapter I. A list of the BEA areas comprising each subregion is presented in Exhibit I-2. The projections are based on the 1972 OBERS projections [1][1/].

WSCC is an extremely large area covering about 50 percent of the contiguous U.S. Despite WSCC's large geographical area, it contained only about 17% of the national population in 1970. WSCC's share of national personal income was 17.6% in 1970. WSCC's share of national personal income and population is expected to only slightly increase between the years 1970 and 2000.

The population growth rate in WSCC is expected to slow from the historical average annual growth rate of 2.8% between 1950 and 1970, to about 0.8% from 1970 through 2000. On the subregional level, the Arizona-New Mexico Power Area is expected to have the highest population growth rate, and the Northwest Power Pool Area is likely to have the lowest.

The distribution of population within WSCC during 1970 and that projected for 2000 is shown as follows:

	Percent of WSCC Population	
Subregion	1970	2000
	%	%
Arizona-New Mexico Power Area	8.9	9.9
Northwest Power Pool Area	23.4	20.9
Rocky Mountain Power Area	7.5	7.6
Northern California-Nevada Power Area	21.6	22.5
Southern California-Nevada Power Area	38.6	39.1

1/ Numbers in brackets refer to references which immediately follow Chapter XII.

Earnings and total personal income in constant dollars are projected to grow, respectively, at 3.4 and 3.5% annually. The Arizona-New Mexico and the Rocky Mountain Power Areas are expected to have the highest earnings growth in the region between 1970 and 2000. The Northwest Power Area is expected to have the lowest growth of total earnings over the same period.

Projections of constant dollar industrial sector earnings indicate that the largest earnings sector in 2000 will be services and government. In terms of national sector earnings totals, the mining, government, and agriculture sectors have a larger portion of earnings originating in WSCC than the other industrial sectors, indicating a concentration of these industries in WSCC. Manufacturing is projected to experience growth consistent with the rest of the Nation. However, the portion of national manufacturing earnings originating in WSCC is significantly less than the portion of other sector earnings in WSCC.

Subregional industrial sector earnings have been analyzed based on the percentage of national sector earnings originating in each subregion for the year 2000. Agriculture earnings are concentrated in the Northwest Power Area. The Rocky Mountain and Arizona-New Mexico Power Areas have a high portion of national earnings concentrated in the services sector. In the Northern California-Nevada Power Area, the transportation utility sector produces the largest percentage of national sector earnings.

Future Electric Power Demand

As discussed in Chapter I, three projections of electricity demand are developed for use in assessing the regional market for hydropower [4,5,32]. From these, the "median" projection is selected. The OBERS population forecasts are adjusted to reflect the latest census [2] as described in Chapter I. The future electricity demands, and adjusted population projections for WSCC, are shown on Sheet 1 of Exhibit IV-2; Sheets 2 through 6 summarize the projections for the five subregions of WSCC.

Energy Demand

The future annual "median" electric-energy consumption in WSCC is expected to grow from 410,100 GWh in 1978 to 579,000 GWh in 1985, representing a compound annual growth rate of 5.1%. By the year 2000, electric energy consumption is expected to grow to about 1,033,100 GWh, representing a compound annual rate of 4.3% between 1978 and 2000.

Energy demand in the Arizona-New Mexico Power area is expected to grow at 6.9% annually between 1978 and 1985. After 1985, growth in energy consumption is expected to slow to an average annual growth rate of 5.6% until 1990, and then to 4.3% through the end of the century. Energy consumption in the year 2000 is likely to be about 119,000 GWh.

In the Northwest Power Pool area, growth in total energy demand between 1978 and 1985 is expected to be 5.5% per year. Between 1985 and 1990, growth in electricity consumption is expected to decrease to 4.3% annually, then to 3.9% until the year 2000. Electrical-energy demand is likely to be about 240,700 GWh in 1985 and 435,700 GWh in 2000.

Total electricity demand in the Northern California Nevada Power area is likely to grow from 79,200 GWh in 1978 to 179,800 GWh in the year 2000, resulting in an average annual growth rate of 3.8%. Average annual growth in the period 1978 to 1985 is expected to be about 4.2%. After 1985, growth in electrical-energy consumption is expected to decline until 1990, and level off at 3.4% in the 1990 through 2000 time frame.

Total electricity demand in the Southern California-Nevada Power area is likely to grow from 102,300 GWh in 1978 to 223,700 GWh in 2000, resulting in an average annual growth rate of 3.6%. Average annual growth in the period between 1978 and 1985 is expected to be about 3.8%. After 1985, growth in electrical-energy consumption is expected to slow and level off at 3.4% between 1990 and 2000.

Electrical-energy demand in the Rocky Mountain Power area is expected to grow at the average annual rate of 4.9% between 1978 and the year 2000. Growth is expected to be high between 1978 and 1985, averaging 6.3% annually. In the 1985 through 1990 period, growth in energy demand is expected to be about 5.0% annually. Growth in energy demand is likely to level off between 1990 and 2000 at about 4.0% annually. Energy demand is expected to increase from 25,900 GWh in 1978 to 74,900 GWh in the year 2000.

Peak Demand

Presently, the U.S. portion of WSCC is a summer peaking region. Three of the four subregions are also summer peaking regions, the only exception being the Northwest Power Pool area which has a winter peak. Growth trends of peak demand follow growth in energy consumption in the subregions. The non coincident peak demand in the WSCC region is

expected to grow at an average annual rate of 5.3% between 1978 and 1985, slightly higher than growth in energy over the same period. Between 1985 and 1990, annual growth in peak demand is expected to be about 4.0% while between 1990 and 2000, growth in peak demand is expected to be about 3.8%. The peak demand is expected to increase from 68,700 MW in 1978 to 174,600 MW by the end of the century.

Load Factor

The WSCC annual load factor in 1978 was reported at 68.1%. Based on the utilities projections, the load factor is expected to decrease to about 67% in 1985, then average 68% through the year 2000. Utilities in California and Nevada are projecting annual load factors averaging 57-58% throughout the 1978-2000 period. The Northwest and Rocky Mountain Power Pool Areas are forecasting higher annual load factors, averaging 65-66%.

Estimate of Electric Power Supply

This section discusses major sources of electric power supply to be considered in developing future expansion plans for power capacity additions in WSCC. The hydropower potential is presented, followed by a discussion on the regional fuel availability.

Hydropower Potential

The data in this section is based on earlier reports and is only used in this volume to provide an indication of the regional hydroelectric power potential. The data is principally used in developing the future generation mix. More definitive information on hydropower potential is contained in the regional report on WSCC.

Table X-1 summarizes the hydropower potential at both existing dams and at undeveloped sites. Hydropower at undeveloped sites is as identified by the Federal Power Commission (now FERC) in 1976 [6]. The identified sites are restricted to those with potential installed capacity greater than 5 MW. Hydropower potential at existing dams was estimated by the U.S. Army Corps of Engineers, Institute for Water Resources (IWR) in July 1977 [7]. The IWR estimate of potential at existing dams is unrestricted with respect to size, and includes dams with a potential installed capacity of less than 5 MW. In 1978, the total installed hydroelectric capacity in WSCC was about 40,665 MW, and the energy production was 189,000 GWh.

Table X-1

WSCC
UNDEVELOPED HYDROPOWER POTENTIAL

Potential at Undeveloped sites (Greater than 5 MW)	Potential Installed Capacity (MW)	Average Annual Energy (1000 MWh)
Arizona New Mexico Power Area	310	1,480
Northwest Power Pool Area	31,740	107,070
Northern California Nevada Power Area	6,680	19,230
Southern California Nevada Power Area	2,090	6,410
Rocky Mountain Power Area	1,900	7,780
WSCC	42,720	141,970
Potential at Existing Dams		
WSCC	18,090	45,550
Total Potential	60,810	187,520

The Northwest Power Pool Area contains 31,740 MW of hydropower potential at undeveloped sites, the largest portion of WSCC potential. The Northern California Nevada Power Area is second in rank of undeveloped hydropower, with approximately 6,680 MW of potential capacity at undeveloped sites. The Southern California Nevada Power Area and the Rocky Mountain Power Area respectively have 2,090 and 1,900 MW of undeveloped hydropower potential. The Arizona New Mexico Power Area has only 310 MW of undeveloped hydropower capacity, the lowest portion of WSCC potential.

Many potential hydroelectric sites in WSCC are located in river segments protected by the Wild and Scenic River Act and are precluded from development. Potential capacity at protected sites has not been included in Table X-1. However, there are many undeveloped sites designated for study under Section 5(a) of the Wild and Scenic Rivers Act (January 1, 1976) and may be restricted from development. These

potentially restricted sites have been included in the summary presented on Table X-1.

The U.S. Army Corps of Engineers survey indicates that the Columbia North Pacific Drainage area has the greatest potential capacity development at existing dams, about 14,000 MW [7].

Availability of Fuels

The WSCC region contains more than 50% of the country's coal resources. There is an estimated 181 billion tons of bituminous and 375 billion tons of sub-bituminous coal in the region (8, 9). Quantities of anthracite and lignite coal are very small. Most of the western coal has less than 1% sulfur content by weight and can meet source performance standards for large boilers established by the U.S. Environmental Protection Agency. The major portion of the coal reserves are located in Montana, Colorado, and Wyoming in areas that are sparsely populated, have limited water resources, and are far from load centers. In order for western coal to be utilized for electricity generation, it has to be transported long distances, or used to generate electricity at the mine mouth for transmission to load centers. To improve coal transportation, six major coal-slurry pipelines originating in WSCC are projected by the year 2000. The projected pipelines originate in the eastern portion of WSCC and are to transport the coal west to the Pacific and southeast to the Gulf of Mexico. The Black Mesa Pipeline is currently operational between Arizona and Nevada, is 273 miles long and has a capacity of 4.8 million tons of coal per year.

The States of California, Colorado, and Wyoming are among the largest producers of oil in the country. In 1976, the average daily production of oil in these three states was 1.5 million barrels of oil per day. This production is expected to increase to 1.8 million barrels per day in 1985, and then drop to about 1.2 million barrels per day in the year 2000. Offshore production is in the Santa Barbara channel and was about 100 thousand barrels per day in 1972. Resources off the Pacific coast both in the Santa Barbara channel and outside the channel are estimated to be 9 billion barrels.

The southeastern portion of WSCC is close to the country's major onshore gas-producing region. Significant production of natural gas occurs in New Mexico and Colorado. Daily production of natural gas in New Mexico and Colorado combined was 1.4 trillion cubic feet in 1976. In 1985, daily production is expected to decrease to 1.3 trillion cubic feet, and to 0.9 in the year 2000.

About 90% of the identified oil shale resources in the U.S. are located in a single geological formation in Colorado, Wyoming, and Utah known as the Green River Formation The Green River Formation underlies 25,000 square mile of land, of which 17,000 square miles are believed to contain oil shale deposits with potential for commercial development. The land overlying the oil shale deposits is sparsely populated and characterized by cliffs, plateaus, escarpments, and some flat land. Water resources required for the mining and milling processes, however, are scarce in the region.

Tar sand deposits have been identified in California, Utah, and New Mexico having over 100 million barrels of oil yield. Thin tar sand deposits have been identified throughout the U.S., but a vast majority of the deposits are located in Utah. There is an estimated 29 billion barrels of oil yield located in Utah.

WSCC uranium resources are primarily located in the States of Wyoming, New Mexico, Colorado, and Utah. Production of Uranium in the four states in 1976 was 12.3 thousand tons. Uranium production is expected to increase to 47.1 thousand tons per year in the year 2000.

The geothermal resources likely to be developed before the year 2000 are located in the western one-third of the country. At the present, there are 14 known geothermal resources areas in California, 13 in Nevada, and 7 in Oregon. There are also some other geothermal areas dispersed throughout the remainder of WSCC.

Load Resources Analysis

This section discusses reserve margins, seasonal system load characteristics, probable system generation mix, and the specific role of hydroelectric power.

Reserve Margins and System Reliability

Due to the unique characteristics of each utility, the uncertainties in water supply for power and energy production, the limited degree of possible interconnections, and other variable parameters, a reserve margin of 25% is applied to the subregional "median" peak demands to compute future generating capacities. However, because of delays in the construction stages or licensing of new plants, some utility reserve margins may fall below the 17% minimum reserve, as discussed in Chapter I, during the next decade.

To enhance its system reliability, WSCC has formed numerous committees and work groups to provide ready and effective means for developing regional operating and planning criteria, compiling regional data banks, and assessing and coordinating the solution of regional problems. There are numerous capacity and energy exchanges between WSCC subregions. The high voltage, high capacity, DC transmission interconnection between the Northern and Southern coastal portions of WSCC greatly enhances the reliability of the entire region. The existing and planned interconnections between subregions are being developed to insure efficient and economical utilization of resources, and at the same time to insure adequacy and reliability. But delays in transmission systems associated with new generation facilities could prevent economy transfers, increase utilization of oil and gas-based energy sources, and reduce system reliability.

In addition, WSCC has some liaison activities with MARCA, and an emergency transfer capability of 100 MW to and from MARCA.

Characteristics of Electric Loads

The weekly load curves for the first week of April, August, and December 1977 of representative utilities in WSCC are presented in Volume III, Exhibit X-6. Table X-2 presents a breakdown of these loads (base, intermediate, and peak) for each of these utilities as explained in Chapter I. These percentages are representative of each season. During each season, the loads may vary by several percent. The portions of the load considered as base, intermediate or peak as shown in Table X-2 are the basis for deriving the generation mix.

From the load curves presented in Volume III, corresponding seasonal tabulations of energy are derived using the computer program described in Appendix A. These tabulations are presented in Exhibit X-3 for each of the representative utilities mentioned above. The use of this information for evaluating hydroelectric power potential is also discussed in Appendix A.

Generation Mix

This section presents future expansion plans. As discussed in Chapter I, an estimate of suggested generation mix for base, interme-

Table X-2

LOAD DISTRIBUTION IN WSCC
(Percent of Annual Peak Load)

Subregion: Representative System:	Base %	Intermediate %	Peak %
Northwest Power Pool Area:			
Bonneville Power Administration			
Off Season	64	3	8
Summer	60	6	2
Winter	80	12	8
Annual	80	12	8
Pacific Power & Light Company			
Off Season	46	17	10
Summer	46	22	5
Winter	65	21	14
Annual	65	21	14
Rocky Mountain Power Area:			
Public Service Company of Colorado			
Off Season	57	14	5
Summer	69	16	15
Winter	66	12	16
Annual	69	15	16
Arizona-New Mexico Power Area			
Arizona Public Service Company			
Off Season	40	12	5
Summer	68	17	15
Winter	40	10	5
Annual	68	17	15
Southern California-Nevada Power Area:			
Southern California Edison Company			
Off Season	48	19	6
Summer	60	22	18
Winter	47	21	10
Annual	60	22	18
Northern California-Nevada Power Area			
Pacific Gas & Electric Company			
Off Season	50	18	7
Summer	66	19	15
Winter	50	18	11
Annual	66	19	15

diate, and peaking capacities is evaluated for WSCC and each of its five subregions. These evaluations are based on existing and planned generation facilities as reported by the utilities, characteristics of electric loads, an analysis of regional resource availability, economic parameters, Federal and state regulations, and other pertinent regional factors. To reflect the uncertainties and unforeseeable factors which can affect future generation mixes, a range of future installed capacity is defined for each major generation source. The projected future capabilities are based on the "median" demand, and the reserve margins presented in Exhibit X-2.

WSCC Summary. The most probable generation mix for WSCC developed from the subregional expansion plans is presented in Table X-3. Between 1978 and 1985, large additions of nuclear and coal capacity are planned by the utilities. After 1985, additions to system capability are expected to be mainly coal, nuclear, hydroelectric and geothermal. It is unlikely that significant oil or gas additions will occur after 1985.

Table X-3

WSCC
GENERATION MIX
(Percent of Total Capability)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	10-12	12-15	15-18	15-18
Coal	15-16	18-20	23-25	30-33
Oil	15-16	12-14	8-10	5-7
Conv. Hydro	20-22	17-18	14-15	10-12
Geothermal	1-2	1-2	1-3	1-3
Intermediate				
Coal 1/	2-3	4-6	6-8	8-10
Oil	7-9	6-8	5-7	3-5
Gas	0-1	0-1	0-1	0-1
Conv. Hydro	5-6	5-6	4-6	4-6
Geothermal	0-1	0-2	0-2	0-2
Other	0-1	1-2	1-2	1-3
Peaking				
Coal 1/	-	-	-	-
Oil	6-7	5-6	4-6	3-5
Gas	2-3	2-3	1-3	1-3
Conv. Hydro	4-6	4-6	3-6	3-6
Pumped Storage	3	3	2-4	2-5
Other	0-1	1-2	1-2	1-3
Total Capability (GW)	135.3	167.0	200.7	241.1

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Northwest Power Pool Area. Table X-4 presents the most likely generation mix for the Northwest Power Pool Area. Dependence on hydroelectric and coal generation is expected to continue into the future,

with nuclear and possibly geothermal generating plants entering into the generation mix. The Bonneville Power Administration (BPA) has been selected to test three, 300-foot diameter experimental wind turbines at a site along the Columbia River Gorge in southern Washington. The three turbines are expected to operate by mid-1981, generating up to 7.5 MW of electricity. However, wind turbine and other nonconventional methods of electric generation are only expected to represent about 4 to 7% of the Northwest Power Pool capacity by the year 2000.

Table X-4

NORTHWEST POWER POOL AREA
GENERATION MIX
(Percent of Total Capability)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	10-12	13-15	15-20	15-20
Coal	17-18	19-20	23-25	26-28
Conv. Hydro	40-42	34-36	28-30	22 25
Intermediate				
Coal	4-6	6-8	6-8	8-10
Conv. Hydro	12-14	10-12	10-12	8-10
Other	0-1	1-2	1-3	2-3
Peaking				
Oil	2-3	2-3	1-2	0-2
Gas	1-2	0-1	0-1	0-1
Conv. Hydro	7-8	7-8	7-8	8-10
Pumped Storage	0-1	0-1	0-1	0-2
Other	0-1	1-3	2-3	2-4
Total Capability (GW)	52.9	65.7	79.5	96.2

Rocky Mountain Power Area. Table X-5 presents the most likely generation mix for the Rocky Mountain Power Area. The area is expected to remain heavily dependent on coal well into the future. Other additions are likely to consist of nominal amounts of nuclear and hydroelectric plants.

Table X-5

ROCKY MOUNTAIN POWER AREA
GENERATION MIX
(Percent of Total Capability)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	2	2-5	2-5	2-5
Coal	50-52	52-55	55-58	55-58
Conv. Hydro	8-10	6-8	5-8	4-6
Intermediate				
Coal 1/	3-5	5-7	6-8	8-10
Oil	4-5	3-5	2-4	1-3
Conv. Hydro	8-9	7-9	6-8	6-8
Other	0-1	0-1	1-2	1-3
Peaking				
Coal 1/	-	-	-	-
Oil	4-6	4-6	4-6	3-5
Gas	2-3	2-3	1-2	1-2
Conv. Hydro	3-5	3-5	3-5	3-5
Pumped Storage	5	4-5	3-5	3-5
Other	0-1	0-1	1-2	1-3
Total Capability (GW)	8.6	10.9	13.3	16.2

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Arizona New Mexico. Table X-6 presents the most likely generation mix for the Arizona New Mexico Power Area. Between 1978 and 1985, additional generating plants will consist primarily of nuclear and coal-fired plants. Then, it is likely that the generation mix will continue to rely primarily on coal. Nuclear capacity is expected to average 20% after 1990.

Table X-6

ARIZONA NEW MEXICO POWER AREA
GENERATION MIX
(Percent of Total Capability)

Generation Type	1985	1990	1995	2000
	%	%	%	%
Base				
Nuclear	17-18	18-22	18-22	18-22
Coal	43-44	44-45	47-50	47-50
Oil	4-6	2-4	0-2	0-2
Intermediate				
Coal 1/	3-4	5-6	7-8	10-12
Oil	12-13	10-11	8-10	6-8
Conv. Hydro	1-2	0-1	0-1	0-1
Other	0-1	0-1	1-2	1-3
Peaking				
Coal 1/	-	-	-	-
Oil	6-7	5-7	4-6	3-5
Gas	4-5	3-5	2-4	2-4
Conv. Hydro	3-4	3-4	2-4	2-4
Pumped Storage	1	1	0-1	1-4
Other	0-1	0-1	1-2	1-3
Total Capability (GW)	14.2	18.5	22.8	28.1

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Southern California Nevada Power Area. Table X-7 presents the most likely generation mix for the Southern California Nevada Power Area. The area will remain heavily dependent upon oil-fired generation sources during the next decade. But as large nuclear and coal-fired plants are installed, the oil-fired units that are being retired will not be replaced in kind.

Table X-7

SOUTHERN CALIFORNIA NEVADA POWER AREA
GENERATION MIX
(Percent of Total Capability)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Nuclear	8-9	15-20	20-25	20-25
Coal	6-7	10-15	15-20	20-25
Oil	42-44	33-35	20-22	15-18
Conv. Hydro	1-2	0-1	0-1	0-1
Intermediate				
Coal 1/	1-2	2-5	3-5	5-8
Oil	17-18	15-17	12-15	10-15
Conv. Hydro	2-3	2-3	1-3	1-3
Other	0-1	0-1	1-2	1-3
Peaking				
Coal 1/	-	-	-	-
Oil	8-10	8-10	6-8	6-8
Gas	2-3	1-3	1-2	0-2
Conv. Hydro	3-4	3-4	2-3	2-3
Pumped Storage	3-4	3-4	3-5	3-5
Other	0-1	0-1	1-2	1-3
Total Capability (GW)	33.4	40.2	47.5	56.2

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Northern California Nevada Power Area. Table X-8 presents the most likely generation mix for the Northern California Nevada Power Area. The present generation mix is heavily dependent upon oil-fired generation sources. Although it will still be a significant portion of the mix, the percentage of oil-fired generation is expected to be reduced to about capacity 15-20% by the year 2000. Hydroelectric generating sources will also reduce percentage-wise, but are also likely

to make up a substantial portion of the generation mix up to the year 2000 and beyond. Coal-fired plants will play ever increasing role as will nuclear. Nuclear capacity is also expected to represent 20 to 25% of the generation mix after 1995.

Table X-8

NORTHERN CALIFORNIA NEVADA POWER AREA
GENERATION MIX
(Percent of Total Capability)

Generation Type	1985	1990	1995	2000
	%	%	%	%
Base				
Nuclear	12-13	17-20	20-25	20-25
Coal	4-6	14-16	18-20	20-25
Oil	25-27	18-20	12-15	8-10
Conv. Hydro	14-16	10-12	8-10	7-10
Geothermal	5-6	5-7	5-7	6-8
Intermediate				
Coal	-	1-2	2-5	4-7
Oil	9-10	8-10	7-10	5-8
Gas	1-2	0-1	0-1	0-1
Conv. Hydro	5-6	5-6	4-6	4-6
Geothermal	1-2	1-2	1-3	2-5
Other	0-1	0-1	1-2	1-3
Peaking				
Oil	3-4	2-3	1-3	1-3
Gas	0-1	0-1	0-1	0-1
Conv. Hydro	3-5	3-5	3-5	3-5
Pumped Storage	6	5	5-6	5-7
Other	0-1	1-2	1-2	1-3
Total Capability (GW)	26.2	31.7	37.5	44.4

Specific Role of Hydropower

Conventional Hydropower. As of December 1978, there was an installed capacity of about 40,665 MW of conventional hydropower, repre-

senting 43% of the total capability in WSCC. The electric energy generated was 189,000 GWh, or 47% of the total 1978 energy demand in WSCC [19].

The Northwest Power Pool has about 70% of the total hydropower capacity in WSCC. The hydropower energy produced was 139,000 GWh in 1978, representing 75% of the total demand in the subregion. As reported by the utilities [32], about 2,500 MW of conventional hydropower are expected to be added between 1979 and 1988. However, the percentage of hydropower energy will steadily decrease. In 1988, hydropower energy is expected to provide only 45% of the "median" demand.

The Northern California-Nevada Area is the second largest user of hydropower in WSCC, having a conventional hydropower capacity of about 6,500 MW. This subregion had an hydroelectric energy production of 28,400 GWh in 1978, representing about 40% of the subregional energy needs. There are some new hydropower plants and additions under construction, licensing or planning among which are New Melones (300 MW), and Kerckhoff 2 (150 MW). Even with these additions, the energy production is expected to fall below the 1978 level, and represent only 16% of the "median" demand by 1988.

The Rocky Mountain Power Area and Southern California-Nevada Area have respectively about 2,100 MW and 2,350 MW of conventional hydropower capacity. Only small additions are planned during the 1980's, and future energy productions in both subregions are expected to average 8,000 GWh per year. Thus, the hydropower energy percentage in the Rocky Mountain Power Area is expected to decrease from 27% in 1978 to about 15% in 1988. In the Southern California-Nevada subregion, the hydropower energy percentage is expected to drop from 13% in 1978 to 6% in 1988.

The Arizona-New Mexico Area had about 700 MW of hydropower capacity in 1978, and an energy production of 2,200 GWh. Currently there is no hydropower under construction and by 1988 the hydropower energy is expected to provide only about 4% of the subregional energy needs.

As shown in Table X-1, the WSCC region has large hydropower potential. Considering the developments already under construction, licensing or planning, as much as 15,000 MW of the total potential of 60,810 MW could be developed by the end of the century.

Pumped Storage. As of December 1978, there was an installed capacity of about 2,100 MW of pumped storage in WSCC. The largest plant is Castaic (1,247 MW) in southern California. Another large pumped-storage plant (Elms, 1,125 MW) is under construction in northern California. In the Rocky Mountain Power Area, in addition to Cabin Creek (268 MW), a new plant (Mont Elbert, 200 MW) is scheduled for full operation in 1981. In the Arizona-New Mexico Area, there are two existing plants at Horse Mesa (44 MW) and Mormon Flat (96 MW), and two 300 MW plants are planned.

With low-cost off peak thermal energy available from large nuclear and coal-fired base-load plants, pumped storage becomes more attractive. The energy output will serve the peaking demand and help reduce the dependence on oil. By the end of the century, pumped storage could represent as much as 5% of the total capacity in WSCC.

Sensitivity Analysis

The projections of future electric demand and supply presented in this chapter are based on numerous factors, each of which is sensitive to public opinion, economics of energy use, and changes in domestic or international policies. The number of variations that could be analyzed is nearly infinite. However, regardless of variations in items, population reflects the ultimate energy use. Of particular importance are variations in projected population growth rates. Such variations will directly affect Projections II and III, since they are based upon per capita energy consumption. Projection I would be indirectly affected as it is based on an aggregation of utility forecasts, each of which may have a different underlying forecast methodolgy. Changes in projected economic growth, rate of implementation of conservation measures, Federal and state regulations, and other regional factors are difficult to gauge but will no doubt affect all of the projections. A general discussion of projection sensitivity is presented in Appendix C.

Changes in the regional population growth rates would definitely affect Projections II and III, and, most likely, the "median" projection. The following table indicates what effects, if any, selected changes in population growth rates would have on the median projection of electric-energy consumption in WSCC.

Percent Change in Population Growth Rates	Percent Change in Energy Demand of Projections II & III in the Year 2000	1/ "New" Median Enegy Demand (GWh)
-50	-10.3	926.5
-15	- 3.2	1012.0
0	0	1033.1
+15	+ 3.3	1053.5
+50	+11.5	1095.6

1/ Median energy demand is computed as the median of Projection I (unchanged) and Projections II and III (adjusted as indicated).

Table C-8 of Appendix C presents the changes in Projections II and III due to changes in the population growth rates for the individual subregions in WSCC.

In WSCC as well as throughout the country, electric-energy conservation measures and load-management measures will most likely be employed in an attempt to offset rising energy prices regardless of other economic activity. Large-scale adoption of conservation will have an effect on electric generation requirements similar to that of depressed economic conditions in that projected demand for both electric power and energy would be reduced. However, conservation will not impede hydroelectric generation, but rather will point to its value and its contribution to conservation. More likely than not, planned thermal-electric generation will be curtailed.

Conversely, if economic activity were to exceed expectations, future demand for energy might exceed the median projection. However, conservation and load-control measures could relieve the capacity situation somewhat, so that electric-energy use would increase to a larger degree than would capacity requirement. Under such circumstance, hydroelectric power and energy would provide operating economy and there would be demand for all that could be economically installed.

To summarize, electric capacity and energy demand could vary widely from the projections, but the overall need for national energy conservation will continue to justify the production of hydroelectric energy.

Chapter XI

ALASKA
FUTURE ELECTRIC POWER DEMAND AND SUPPLY

Introduction

This chapter presents future electric demands and power resources in Alaska and assesses potential for utilization of new hydropower resources. The assessment includes fixed factors and projection of variable factors to the year 2000, among which are the following:

1. Population and economic growth,
2. Electric power and energy demand,
3. Hydropower potential,
4. Availability of fuel resources,
5. Characteristics of electric loads,
6. Generation mix by type of fuel, and
7. Hydropower utilization.

The underlying assumptions and methodology of the projections presented in this chapter are described in Chapter I. In addition, in depth discussions of load curves, attractiveness of hydropower, and projection sensitivity are presented in Appendices A, B, and C respectively. The combination of Chapter I, this chapter, and the appendices summarizes the future electric-energy demand and supply and the potential role of hydropower in Alaska.

Alaska is separate from the contiguous United States and is not tied into the interconnected electric system of the U.S. In this study, it is considered as a independent region and only the electric-power demand and supply from the electric utilities is analyzed. Electricity generated by private industry and military installations have not been included.

An overview of the electrical situation, with emphasis on the role of hydropower, in Alaska for 1978 is discussed in Chapter XI of Volume III. Included in that volume are a description of power systems which are bulk power suppliers in the State, an analysis of the existing regional electrical-power demand and supply, and a load resource balance.

Demographic and Economic Growth

Exhibit XI-1 summarizes the significant demographic and economic projections for Alaska, as approximated by BEA economic area 172. The projections are based on the 1972 OBERS projections [1].[1/] The OBERS projections forecast an average annual population growth rate of about 1.6% between 1980 and 1990, then 1.1% to the year 2000.

The largest portion of Alaskas' earnings is likely to be generated from the government sector, which is exepcted to supply about 40% of the region's total earnings in 2000. The mining sector, although small in magnitude, has the largest portion of national earnings compared to other Alaska industrial sectors. Total earnings in Alaska are expected to grow about 3.7 percent annually between 1980 and 2000.

Per capita income in Alaska is expected to be much higher than the national average. In 1980, the Alaska per capita income is likely to be 18% above the national average, and decrease to 14 percent above in the year 2000. Overall growth in Alaska per capita income is expected to be about 2.6 percent in constant dollars between 1980 and 2000.

Future Electric Power Demand

As discussed in Chapter I, three projections of electricity demand are developed for use in assessing the regional market for hydropower [4, 5, 33]. From these, the "median" projection is selected. The OBERS population forecasts are adjusted to reflect the latest census [2] as described in Chapter I. The future electricity demands, and adjusted population projections for Alaska are shown on Exhibit XI-2.

Energy Demand

The future annual "median" electric-energy consumption in Alaksa is expected to grow from 2,300 GWh in 1978 to 3,700 GWh in 1985, representing a compound annual growth rate of 7.2%. By the year 2000, electric-energy consumption is expected to grow to about 7,500 GWh, representing a compound annual rate of 5.6% between 1978 and 2000.

1/ Numbers in brackets refer to references which immediately follow Chapter XII.

Peak Demand

Alaska is a winter peaking region. The peak demand is expected to grow from 500 MW in 1978 to 1,700 MW in 2000, resulting in an average annual growth rate of 5.4% between 1978 and 2000.

Load Factor

Alaska presently has the lowest regional annual load factor in the Nation. The annual load factor is expected to remain at about its present value of 50% through the remainder of the century.

Estimate of Electric Power Supply

This section discusses major sources of electric power supply to be considered in developing future expansion plans for power capacity additions in Alaska. The hydropower potential is presented, followed by a discussion on the regional fuel availability.

Hydropower Potential

The data in this section is based on earlier reports and is only used in this volume to provide an indication of the regional hydroelectric power potential. The data is principally used in developing the future generation mix. More definitive information on hydropower potential is contained in the regional reporton Alaska.

Table XI-1 summarizes the hydropower potential at both existing dams and undeveloped sites. Hydropower at undeveloped sites is as identified by the Federal Power Commission (now FERC) in 1976 [6]. The identified sites are restricted to those with potential installed capacity greater than 5 MW. Hydropower potential at existing dams was as estimated by the U.S. Army Corps of Engineers, Institute for Water Resources (IWR) in July 1977 [7]. The IWR estimate of potential at existing dams is unrestricted with respect to size, and includes dams with a potential installed capacity of less than 5 MW. In 1978, there was an installed hydropower capacity of about 130 MW in the State of Alaska.

Table XI-1

ALASKA
UNDEVELOPED HYDROPOWER POTENTIAL

	Potential Installed Capacity (MW)	Average Annual Energy (1000 MWh)
Potential at undeveloped sites (greater than 5 MW)	33,250	175,665
Potential at Existing Dams	119	535
Total Potential	33,369	176,200

It is well known that Alaska has extensive hydroelectric resources. More than 100 potential hydroelectric sites have been identified by the Federal Power Commission, now FERC. The projected capacity of these potential sites varies greatly from a few MW to the 5,000 MW estimated for the Rampart site on the Yukon River. Some other river basins, such as the Noatak, Koyukuk, Susitna, Cooper, and Stikine River also have large hydropower potentials. Most of the existing dams are located in the southcentral areas, and are already developed for hydropower generation.

Availability of Fuels

Alaska has very large-measured hydrocarbons reserves, with about 10 billion barrels of oil and 32 trillion cubic feet of natural gas [8,9,34]. The major fields are in the North Slope, the Cook Inlet, and the Pacific Margin.

The actual total recoverable coal resources are estimated at 130 billion tons. Major coal beds are located in the interior, northwest, and southcentral regions of the State. Other occurences and small fields are scattered throughout the State. Alaska coals are graded from lignite to bituminous, and their heating value varies with location from 6,000 to 14,000 BTU/lb.

Alaska has an estimated 11 billion barrels of oil shale in the northwest and northern areas, but these deposits are remote from probable markets. In addition, techniques used in recovery of

hydrocarbons from oil shale are not yet fully developed and are very expensive. Due to these handicaps, it is believed that oil shale will not be of practical value for electricity generation within the time frame of this study.

There are a number of locations in the State where geothermal power could be developed. However, many locations are in isolated areas, resulting in high construction costs for the geothermal plants and high costs of long-range transmission lines. Because of these high costs, major geothermal emphasis would initially be concentrated in areas close to established electrical loads. Only a few small geothermal projects are expected to be developed before the end of the century.

Among the new sources, solar energy is not expected to play any role in commercial electric-power generation because of the low-incident radiation. Although coastal regions typically have high average winds, wind energy developments on a commercial scale will likely require public subsidy support to move past the demonstration project level. There are many coastal areas in Alaska where the combination of a large tidal range and topographic features produce impressive tide races. Primarily these are located in the southeast region Prince William Sound, Cook Inlet, and Kodiak Island. But most tide races are not located close enough to communities to warrant interest as potential electric-energy sources.

Load Resources Analysis

This section discusses reserve margins, seasonal system load characteristics, probable system generation mix, and the specific role of hydroelectric power.

Reserve Margin and System Reliability

Due to the large distance between load centers and the adverse terrain between them, most Alaskan utility systems do not have transmission line interconnections. Thus, the reliability of power within a particular generation system relies primarily on an adequate reserve margin. For that reason, reserve margins as presented in Exhibit XI-2, are currently very high and are expected to remain so. There are studies currently under way to determine the feasibility of an interconnection between the southcentral and Yukon Areas, which would tie Anchorage and Fairbanks together. This line would probably be constructed only if the Upper Susitna hydropower project (now under

study) is built. For the purpose of this study, a reserve margin of 50% is applied to the "median" peak demand to compute future capacity requirements.

Characteristics of Electric Loads

The weekly load curves for the first week of April, August, and December 1977 of representative utilities in Alaska are presented in Volume III, Exhibit XI-6. Table XI-2 presents a breakdown of these loads (base, intermediate, and peak) for each of these utilities as explained in Chapter I. These percentages are representative of each season. During each season, the loads may vary by several percent.

Table XI-2

LOAD DISTRIBUTION IN ALASKA
(Percent of Annual Peak Load)

Representative Utility	Base %	Intermediate %	Peak %
Chugach Electric Association, Inc.			
Off Season	42	10	7
Summer	30	14	2
Winter	79	13	8
Annual	79	13	8
Golden Valley Electric Association, Inc.			
Off Season	40	8	8
Summer	22	4	4
Winter	80	13	7
Annual	80	13	7
Fairbanks Municipal Utilities System			
Off Season	48	20	6
Summer	41	18	8
Winter	74	16	10
Annual	74	16	10

For the three utilities representative of Alaska, the average annual base load varies between 74 and 80%, and the peak load range varies between 8 and 10% of the peak annual demand. The portions of the load considered as base, intermediate or peak are the basis for

deriving the generation mix which is presented in the next section. Table XI-2 reflects the extremely large load differential between winter and the remaining seasons of the year.

From the load curves presented in Volume III, corresponding seasonal tabulations of energy are derived using the computer program described in Appendix A. These tabulations are presented in Exhibit XI-3 for each of the representative utilities mentioned above. The use of this information for evaluating hydroelectric power potential is also discussed in Appendix A.

Generation Mix

This section presents future expansion plans. As discussed in Chapter I, an estimate of suggested generation mix for base, intermediate, and peaking capacities is evaluated for Alaska. These evaluations are based on existing and planned generation facilities as reported by the utilities, characteristics of electric loads, an analysis of regional resource availability, economic parameters, Federal and state regulations, and other pertinent regional factors. To reflect the uncertainties and unforeseeable factors which can affect future generation mixes, a range of future installed capacity is defined for each major generation source. The projected future capabilities are based on the "median" demand, and the reserve margins presented in Exhibit XI-2.

Alaska Regional Summary. Table XI-3 shows the most probable generation mix to the year 2000 for Alaska. In the past, Alaska has relied on combustion turbines as its principal source of electricity generation due to their low construction costs and the availability of low cost natural gas for fuel. However, this trend is expected to change in the future. Many coal-fired plants are now under construction or planned for the near future. In addition, because of higher fuel costs, many small hydropower plants are becoming economical to serve isolated areas. Several small hydropower developments are now under construction or licensing. The Susitna project, now in the planning stage, could provide a large amount of the Anchorage-Fairbanks electrical need by the end of the century. Many other large hydroelectric project sites exist and could be economically developed in the future. Although interest has been expressed in a nuclear generating plant for commercial use, it is considered unlikely that such a powerplant would be in operation before the year 2000 due to excessive leadtime and economic competition from hydroelectric and coal-electric generation sources [34].

Table XI-3

ALASKA GENERATION MIX
(Percent of Total Capability)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Coal	15-18	18-20	20-25	20-25
Oil	12-14	10-12	8-10	5-8
Gas	38-42	34-36	25-27	15-18
Conv. Hydro	2-4	5-10	10-20	20-30
Intermediate				
Coal	2-4	3-5	3-5	3-5
Oil	5-6	4-5	4-5	3-5
Gas	5-6	5-6	4-6	4-6
Conv. Hydro	3-4	3-4	3-8	5-10
Other	0	0-1	0-1	1-2
Peaking				
Oil	3-4	2-3	2-3	1-3
Gas	3-4	3-4	3-4	2-4
Conv. Hydro	2-3	2-3	4-6	5-10
Other	0	0-1	0-1	1-2
Total Capability (GW)	1.2	1.7	2.1	2.6

Specific Role of Hydropower

With a capacity of 131 MW, conventional hydropower represented about 14% of the total installed capacity in 1977. Because there are only two small hydropower developments under construction at Solomon Gulch and Swan Lake, the role of hydropower is decreasing rapidly. But there are many hydropower sites available for development. Several studies of small and medium-size hydropower developments are under way. The controversial Susitna project with an estimated capacity of 1,500 MW has been the object of many studies, and the construction of the Watana and Devil Canyon dams are under consideration. If these projects are approved, it is likely that Anchorage and Fairbanks will be connected, greatly enhancing the reliability of the two systems.

At this time, there are no pumped-storage facilities in the State and none are planned by the utilities. As there are many conventional hydropower sites to be developed, there is no economic incentive to develop a pumped-storage project.

Sensitivity Analysis

The projections of future electric demand and supply presented in this chapter are based on numerous factors, each of which is sensitive to public opinion, economics of energy use, and changes in domestic or international policies. The number of variations that could be analyzed is nearly infinite. However, regardless of variations in items, population reflects the ultimate energy use. Of particular importance are variations in projected population growth rates. Such variations will directly affect Projections II and III, since they are based upon per capita energy consumption. Projection I would be indirectly affected as it is based on an aggregation of utility forecasts, each of which may have a different underlying forecast methodolgy. Changes in projected economic growth, rate of implementation of conservation measures, Federal and state regulations, and other regional factors are difficult to gauge but will no doubt affect all of the projections. A general discussion of projection sensitivity is presented in Appendix C.

Changes in the regional population growth rates would definitely affect Projections II and III, and, most likely, the "median" projection. The following table indicates what effects, if any, selected changes in population growth rates would have on the median projection of electric energy consumption in Alaska.

Percent Change in Population Growth Rates	Percent Change in Energy Demand of Projections II & III in the Year 2000	1/ "New" Median Enegy Demand (GWh)
-50	-17.2	6.2
-15	- 6.9	7.1
0	0	7.5
+15	+ 5.2	7.9
+50	+19.0	8.9

1/ Median energy demand is computed as the median of Projection I (unchanged) and Projections II and III (adjusted as indicated).

Alaska is rich in natural resources. The rate of development of these resources, especially its hydrocarbon reserves, will greatly affect the demographic and economic growth of the State. These uncertainties about future developments in Alaska are reflected in the wide range of projections. If the oil exploration, and other related activities continue their rapid expansion, future electricity demand might exceed the median projection by as much as 25%. Under this high scenario of development there will be a need for more installed capacity which could be provided by a faster development of potential hydroelectric sites.

Except for the areas near Anchorage and Fairbanks which are interconnected, most of the electric load centers are isolated. Their electrical needs are principally met by thermal generation fueled by oil. At the present time, many of these small communities are investigating and finding out that small-capacity hydro developments are economical. As the price of oil is expected to escalate much more rapidly than inflation, hydroelectric developments which today are uneconomical or marginal will soon become very attractive.

Chapter XII

HAWAII
FUTURE ELECTRIC POWER DEMAND AND SUPPLY

Introduction

This chapter presents future electric demands and power resources in Hawaii, and assesses potential for utilization of new hydropower resources. The assessment includes fixed factors and projection of variable factors to the year 2000, among which are the following:

1. Population and economic growth,
2. Electric power and energy demand,
3. Hydropower potential,
4. Availability of fuel resources,
5. Characteristics of electric loads,
6. Generation mix by type of fuel, and
7. Hydropower utilization.

The underlying assumptions and methodology of the projections presented in this chapter are described in Chapter I. In addition, in-depth discussions of load curves, attractiveness of hydropower, and projection sensitivity are presented in Appendices A, B, and C respectively. The combination of Chapter I, this chapter, and the appendices summarizes the future electric-energy demand and supply, and the potential role of hydropower in Hawaii.

An overview of the electrical situation with emphasis on the role of hydropower in Hawaii for 1978 is discussed in Chapter XII of the Volume III. Included in Volume III are a description of power systems in Hawaii, an analysis of regional electric-power demand and supply, and a load resource balance. The map of the Hawaii region is shown on the national map on Exhibit I-1.

The isolated nature of the load centers and supply sources in the State of Hawaii necessitates an independent analysis of future trends. The diversification in demand trends is a direct result of the varying economic bases and sizes of the Hawaiian Islands. The six main inhabited islands of the Hawaiian chain are served by five utilities as follows:

Island	Company
Oahu	Hawaiian Electric Company (HECO)
Hawaii	Hawaii Electric Light Company (HECO)
Kauai	Kauai Electric Division of Citizens Utility Company (KED)
Maui-Lanai	Maui Electric Company (MECO)
Molokai	Molokai Electric Company (MOECO)

The projection of future demand and supply balances for Hawaii are made for individual utilities, and aggregated to obtain the projections for the State. Electric supply projections are those for electric utilities only; no attempt is made to assess electric-energy generation from industrial sources.

Demographic and Economic Growth

Exhibit XII-1 summarizes the significant demographic and economic projections for Hawaii. The demographic and economic projections are for BEA economic area 173, encompassing all of islands in the State of Hawaii. The projections are based on the 1972 OBERS projections [1].1/

Although the OBERS population projections are somewhat low, projections of earning and income are useful to show the relative magnitude of earnings in various industrial sectors. OBERS projects average annual growth in earnings and total personal income at 3.5 and 3.6% respectively between 1970 and 2000. Trade, services, and government sectors are expected to have the highest industrial sector earnings.

Per Capita Income in Hawaii was higher than the national average in 1970, and is expected to remain so throughout the projected period. The disparity between the national average and Hawaii per capita income is expected to decrease over time. Between 1970 and 2000, per capita income is expected to grow at 2.5% annually.

1/ Numbers in brackets refer to references which immediately follow Chapter XII.

Future Electric Power Demand

As discussed in Chapter I, three projections of electricity demand are developed for use in assessing the regional market for hydropower [4,5,35]. From these, the "median" projection is selected. The OBERS population forecasts are adjusted to reflect the latest census [2] as described in Chapter I. The future electricity demands, and adjusted population projections for Hawaii are shown in Exhibit XII-2.

Energy Demand

The "median" electric energy demand in Hawaii is expected to grow from 6,800 GWh in 1978 to 9,100 GWh in 1985, representing an average annual growth rate of 4.3%. The electric-energy demand is expected to grow to approximately 15,800 GWh by the year 2000, resulting in an average annual growth rate of 3.9% between 1978 and 2000.

The island of Oahu currently consumes the largest portion of electrical energy generated. The island of Maui is expected to have an accelerated growth in demand because of the expanding tourist industry.

Peak Demand

Presently, Hawaii has its peak demand in winter, and it is expected to remain so in the future. Between 1978 and 1985, the peak demand is likely to grow at the average annual rate 4.5%, from 1,100 MW to 1,500 MW. After 1985, annual growth in peak demand is likely to be about 4.0% until 1990, then 3.6% through the end of the century. The peak demand is expected to be 2,600 MW in 2000.

Load Factor

In 1978, Hawaii had an annual load factor of 69.5%. From the projected peak and energy demands forecast by the utilities, future load factors are expected to average 69%.

Estimate of Electric Power Supply

This section discusses major sources of electric power supply to be considered in developing future expansion plans for capacity additions. The hydropower potential is presented followed by a discussion on the regional fuel availability.

Hydropower Potential

The data in this section is based on earlier reports and is only used in this volume to provide an indication of the regional hydroelectric power potential. The data is principally used in developing the future generation mix. More definitive information on hydropower potential is contained in the regional report on Hawaii.

Table XII-1 summarizes hydropower potential at existing dams and at undeveloped sites. Hydropower at undeveloped sites is as identified by the Federal Power Commission (now FERC) in 1976 [6]. The identified sites are restricted to those with potential installed capacity greater than 5 MW. Hydropower potential at existing dams is as estimated by the Institute for Water Resources (IWR) in July 1977 [7]. The IWR estimate of potential at existing dams is unrestricted with respect to size, and includes dams with a potential installed capacity of less than 5 MW. In 1978 Hawaii had 20 MW of installed hydroelectric capacity which produced about 100,000 MWh of energy.

Table XII-1

HAWAII
UNDEVELOPED HYDROPOWER POTENTIAL

	Potential Installed Capacity (MW)	Average Annual Energy (1000 MWh)
Potential at Undeveloped Sites (greater than 5 MW)	35.0	229.0
Potential at Existing Dams	33.5	57.4
Total Potential	68.5	286.4

There are few available sites for additional hydroelectric power development. Firm flow at most sites does not exceed 40 cfs, requiring an effective net head of 1,700 feet to produce only 5 MW. Run-of-river sites exhibiting such physical characteristics simply do not exist. There are potential sites, that could incorporate storage facilities with long penstocks to achieve a suitable combination of head and storage but are prohibitively costly. Previous studies have

also been performed by the U.S. Army Engineer District in Honolulu [36], and the most attractive hydropower sites in terms of engineering, cost, and environmental aspects are summarized in Table XII-2.

Table XII-2

POTENTIAL HYDROELECTRIC DEVELOPMENT SITES

Island	SITE	CAPACITY (MW)	ENERGY (GWH)
Kauai	Waimea River 1/	3.91	7.5
	Wailua River 2/	10.1	21.7
	Alexander Reservoir 1/	2.02	3.5
Oahu	Wahiawa Reservoir 3/	2.82	7.5
Molokai	Kaulapu'u Reservoir 3/	0.09	0.55
Maui	Hamakua Ditch 4/	0.5	2.5
	Hoopoi Chute 4/	2.0	3.0
Hawaii	Union 4/	0.5	4.1

1/ New incremental potential for existing powerplants.
2/ Undeveloped site in the early stage of a three-year survey study by Pacific Ocean Division, Corps of Engineers.
3/ New potential for existing reservoir.
4/ Undeveloped sites.

Availability of Fuels

The major source of energy in Hawaii is fuel oil. Consequently, the major generating equipment in Hawaiian Electric Company's system is designed to burn residual fuel oil. Even with today's critical oil situation, oil remains Hawaii's most economical source of energy.

Geothermal energy may provide a substantial portion of Hawaii's energy needs in the future. By early 1981, it is expected that electricity from the east rift zone of Kilauea Volcano will be feeding the power grid of Hawaii Electric Light Company. In 1978, the U.S. Navy was planning to contract for experimental drilling in search of geothermal energy on government land in the Luaualei area of Oahu.

Nuclear energy has been kept under review by Hawaii's utilities, but at present appears uneconomical because even the smallest commercial reactors are too large for integration into the electric system.

The best wind spots in the Hawaiian Islands include Kahuku on Oahu, Kahua Ranch on the Big Island, West Molokai and McGregor Point on Maui. A 200-kilowatt wind machine has been built at Kahuku. It is a model MOD-1 machine designed and built by Boeing Aircraft and paid for by the Federal government. Hawaiian Electric has signed a letter of intent to buy the power produced from thirty-two 1,500-kilowatt wind machines.

The energy generated by bagasse (waste from sugarcane) is significant. Bagasse is used primarily in industrial boilers, but is also available for public consumption. In 1978, bagasse supplied 38 percent of the energy requirements of the Big Island and 23 percent of Kauai's. Lihue Plantation Co. is building a bagasse powerplant, which will produce 12 MW of power on Kauai. The construction is near completion.

Ocean thermal-energy conversion (OTEC) may be able to contribute to the islands' electric power supply in the future. OTEC uses the thermal-energy differential between the warm surface and cold deep-ocean water. A small demonstration plant, Mini OTEC, is now under test off the coast of Hawaii, and has proved successful. The plant is producing 50-kilowatts of electricity at an estimated cost of $3,000 per kilowatt. Conceptual OTEC designs of 200 MW have been made. However, problems of marine fouling of equipment and transmission of the electric energy must be overcome.

Load Resources Analysis

This section discusses reserve margins, seasonal system load characteristics, probable generation mix, and the specific role of hydropower.

Reserve Margin and System Reliability

The reserve margin used for projecting system capacity in this study is that projected by the utilities for individual systems. The demand and supply projections for each utility are aggregated to obtain demand and supply projections for Hawaii. The resulting reserve margins are used to obtain the system capability from the "median" projection of demand. Average system reserve margins projected for the utilities range from 12% for MECO to 32% for KED. To provide adequate and reasonable power supply to meet the "median" peak demand, a reserve margin of 25% is applied to compute future generating capacities.

Characteristics of Electric Loads

The weekly load curves for the first week of April, August, and December 1977 of representative utilities in Hawaii are presented in Volume III, Exhibit XII-6. Table XII-3 presents a breakdown of the loads (base, intermediate, and peak) for Hawaiian Electric Company, Inc. (HECO) as explained in Chapter I. These percentages are representative of each season, and the annual loads are the basis for deriving the generation mix. During each season, the loads may vary by several percent. The other representative Hawaiian utilities are much smaller than HECO. Their small size and resulting lack of load diversity makes it difficult to draw conclusions concerning their load demands.

Table XII-3

LOAD DISTRIBUTION IN HAWAII
(Percent of Annual Load)

Representative Utility:	Base %	Intermediate %	Peak %
Hawaiian Electric Company, Inc.:			
Off Season	48	30	12
Summer	56	28	14
Winter	50	33	17
Annual	56	27	17

From the load curves presented in Volume III, corresponding seasonal tabulations of energy are derived using the computer program described in Appendix A. These tabulations are presented in Exhibit XII-3. The use of this information for evaluating hydroelectric power potential is also discussed in Appendix A.

Generation Mix

This section presents future expansion plans. As discussed in Chapter I, an estimate of suggested generation mix for base, intermediate, and peaking capacities is evaluated for Hawaii. These evaluations are based on existing and planned generation facilities as reported by the utilities, characteristics of electric loads, an analysis of regional resource availability, economic parameters, Federal and state regulations, and other pertinent regional factors. To reflect the uncertainties and unforeseeable factors which can affect future generation mixes, a range of future installed capacity is defined for

each major generation source. The projected future capabilities are based on the "median" demand, and the reserve margins presented in Exhibit XII-2.

Hawaii Regional Summary. Table XII-4 presents the most probable generation mix to the year 2000. It is expected that oil will continue to be the main source of electrical energy. Since Hawaii has no fossil-fuel resources of its own, it must rely on imports from the mainland and foreign sources. In order to reduce dependence on oil, Hawaii is focusing research and development on proven alternate energy sources that can be developed in a reasonable time. Alternate energy sources that should prove economical for providing Hawaii's energy needs in the future are geothermal and improved utilization of sugarcane waste.

Table XII-4

GENERATION MIX
HAWAII
(Percent of Total Capability)

Generation Type	1985 %	1990 %	1995 %	2000 %
Base				
Oil	55-57	55-57	50-55	50-55
Geothermal	0	0	0-5	0-5
Intermediate				
Oil	22-24	20-22	20-22	20-22
Gas	3-5	2-4	1-3	0-2
Geothermal	0	0	0-5	0-5
Bagasse	0-2	0-3	2-5	2-5
Conv. Hydro	0-1	0-1	0-1	0-1
Other	0	0-1	0-1	1-2
Peaking				
Oil	15-18	15-18	12-15	12-15
Bagasse	0-3	0-3	2-5	2-5
Other	0	0-1	0-1	1-2
Total Capability (GW)	1.9	2.3	2.7	3.3

Specific Role of Hydropower

As of December 1978, there was about 20 MW of installed capacity, with an average annual energy production of 100 million kWh, representing 1% of the total energy needs. Hydropower resources are mainly on a "run-of-river" type, because of the lack of storage capacity at the sites. As no hydropower plants are under construction, the role of hydropower will decrease. The most attractive sites are summarized in Table XII-2. Because of the high engineering and construction costs for the power and energy available, these new sites are not yet planned for development. Pumped-storage development on the islands will not be realized this century principally because of the lack of economical pumping energy.

Sensitivity Analysis

The projections of future electric demand and supply presented in this chapter are based on numerous factors, each of which is sensitive to public opinion, economics of energy use, and changes in domestic or international policies. The number of variations that could be analyzed is nearly infinite. However, regardless of variations in items, population reflects the ultimate energy use. Of particular importance are variations in projected population growth rates. Such variations will directly affect Projections II and III, since they are based upon per capita energy consumption. Projection I would be indirectly affected as it is based on an aggregation of utility forecasts, each of which may have a different underlying forecast methodolgy. Changes in projected economic growth, rate of implementation of conservation measures, Federal and state regulations, and other regional factors are difficult to gauge but will no doubt affect all of the projections. A general discussion of projection sensitivity is presented in Appendix C.

Changes in the regional population growth rates would definitely affect Projections II and III, and, most likely, the "median" projection. The following table indicates what effects, if any, selected changes in population growth rates would have on the median projection of electric-energy consumption in Hawaii.

Percent Change in Population Growth Rates	Percent Change in Energy Demand of Projections II & III in the Year 2000	"New"[1/] Median Enegy Demand (GWh)
-50	-13.3	13.7
-15	- 3.8	15.2
0	0	15.8
+15	+ 4.4	16.5
+50	+15.2	18.2

1/ Median energy demand is computed as the median of Projection I (unchanged) and Projections II and III (adjusted as indicated).

Hawaii has a limited amount of industrial activity and the agricultural sector is already well developed. The main source of economic growth depends on the development of the tourism and recreational activities, but it is limited by the size of the islands. Projections II and III which are based on national per capita energy consumption, are not truly representative of the islands development. Projection I which is based on the utilities forecasts is certainly more representative of the future demand. Regardless of what will be the annual growth rate during the next twenty years, Hawaii is and will remain dependent on imported oil, and as such, on increasing energy prices. Any feasible development of renewable resources will benefit Hawaii.

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21 Harza Engineering Company, "Underground Pump-Storage in the Menominee Iron Range" Wisconsin Michigan Power Company, October 25, 1973.

22 MAAC, Regional Reliability Council, "Coordinated Bulk Power Supply Program", April 1, 1979.

23 MAIN, Regional Reliability Council, "Coordinated Bulk Power Supply Program", April 1, 1979

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28 NPCC, Regional Reliability Council, "Coordinated Bulk Power Supply Program", April 1, 1979.

29 SERC, Regional Reliability Council, "Coordinated Bulk Power Supply Program," April 1, 1979.

30 SWPP, Regional Reliability Council, "Coordinated Bulk Power Supply Program," April 1, 1979.

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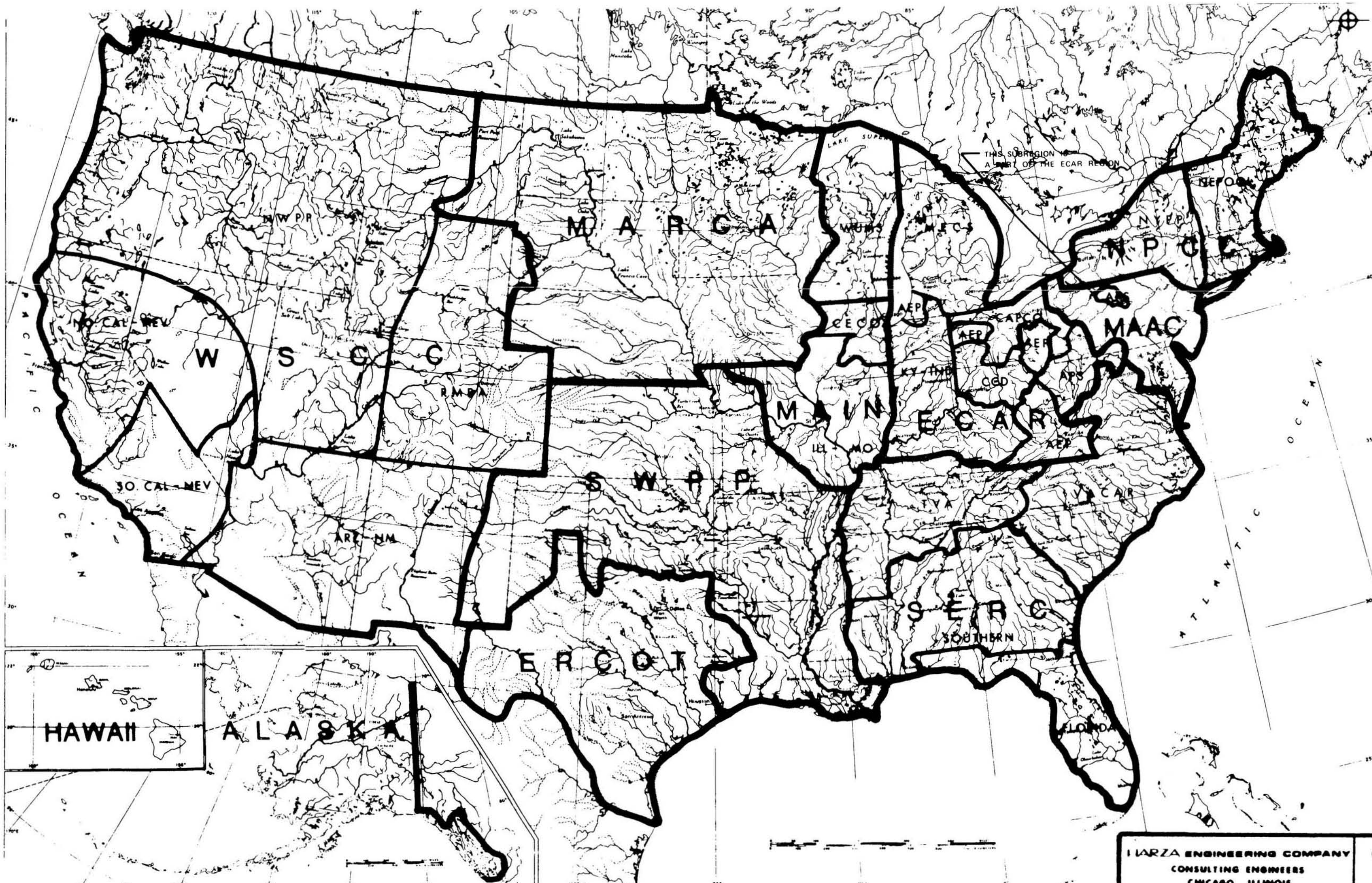

LEGEND :

— DELINEATES THE REGIONAL ELECTRIC RELIABILITY COUNCILS.

— DELINEATES THE SUB-REGIONS WITHIN A REGIONAL ELECTRIC RELIABILITY COUNCIL.

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THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **STUDY REGIONS APPROXIMATED BY UTILITY SERVICE AREAS**	
CONTRACT NO DACW72 78 - C - 0013 DATE MARCH 1980	EXHIBIT I-1

East Central Area Reliability Coordination Agreement (ECAR)
- Allegheny Power System (APS) - 19,65,66.
- American Electric Power (AEP) - 20,51,52,64,76.
- Central Area Power Coordination Group (CAPCO) - 67,68,70.
- Cincinnati Columbus Dayton Group (CCD) - 62,63,69.
- Michigan Electric Coordinated System (MECS) - 71,72,73,74.
- Kentucky-Indiana (KY-IND) - 53,54,55,56,59,60,61,75.

Mid-America Interpool Network (MAIN)
- Commonwealth Edison (CECO) - 77,79,82.
- Wisconsin - Upper Michigan System (WUMS) - 83,84,85,86.
- Illinois - Missouri (ILL-MO) - 57,58,78,112,113,114.

Mid-Atlantic Area Council (MAAC) - 10,11,13,14 1/,15,16,17.

Mid-Continent Area Reliability Coordination Agreement (MARCA) - 80,81,87,88,89,90,91,92,93,96,97,98,99,100,101,102, 103,104,105,106,107,108.

Northeast Power Coordinating Council (NPCC)
- New England (NEPOOL) - 1,2,3,4,5.
- New York Power Pool (NYPP) - 6,7,8,9,12,14 1/.

Southeastern Electric Reliability Council (SERC)
- Virginia - Carolinas Subregion (VACAR) - 18 2/, 21,22,23,24,25, 26,27,28,29,30,31.
- Tennessee Valley Authority (TVA) - 46,47,48,49,50.
- Southern Companies Subregion (SOUTHERN) - 32,33,39,40,41, 42,43,44,45,136,137.
- Florida Subregion (FLORIDA) - 34,35,36,37,38.

Southwest Power Pool (SWPP) - 109,110,111,115,116,117,118, 119,120,122,130,131,132,133,134,135,138,139,140.

Electric Reliability Council of Texas (ERCOT) - 121,123,124, 125,126,127,128,129,141,142,143,144.

Western Systems Coordinating Council (WSCC)
- Northwest Power Pool Area (NWPP) - 94,95,151,152,153,154, 155,156,157,158,159.
- Rocky Mountain Power Area (RMPA) - 147,148,149,150.
- Arizona - New Mexico Power Area (ARZ-NM) - 145,146,162,163.
- Southern California - Nevada Power Area (SO. CAL-NEV) - 161, 164,165,166.
- Northern California - Nevada Power Area (NO. CAL-NEV) - 160, 167,168,169,170,171.

Alaska - 172.

Hawaii - 173.

1/ BEA 14 divided into two parts for analysis.

2/ BEA 18 includes the Washington D.C. Metropolitan area which actually is a part of MAAC.

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CONTRACT NO. DACW72 - 78 - C - 0013 DATE MARCH, 1980	EXHIBIT I-2

POPULATION
AVERAGE ANNUAL GROWTH RATE
FOR THE PERIODS

Region Sub-Region	1970-1978 %	1978-1985 %	1985-1990 %	1990-1995 %	1995-2000 %
ECAR					
APS	0.81	0.5	0.2	0.1	0.1
AEP	0.21	0.5	0.8	0.5	0.5
CAPCO	0.11	0.4	0.6	0.5	0.5
CCD	0.11	0.5	0.9	0.6	0.6
KL-IND	0.66	0.9	1.1	0.8	0.8
MECS	0.43	0.7	0.9	0.7	0.7
MAAC	0.17	0.4	0.8	0.7	0.7
MAIN					
CECO	0.15	0.5	0.8	0.7	0.7
ILL-MO	0.28	0.4	0.6	0.4	0.4
WUMS	0.72	0.7	0.6	0.5	0.5
MARCA	0.54	0.5	0.5	0.4	0.4
NPCC					
New England	0.43	0.7	0.9	0.7	0.7
New York	(0.34)	0.2	0.8	0.7	0.7
SERC					
VACAR	1.28	1.4	1.5	1.0	1.0
TVA	1.31	1.3	1.2	0.7	0.7
SOUTHERN	1.19	1.2	1.1	0.6	0.6
FLORDIA	2.99	2.6	2.1	1.5	1.5
SWPP	1.14	0.9	0.6	0.4	0.4
ERCOT	1.90	1.5	1.2	0.8	0.8
WSCC					
NWPP	1.79	1.2	0.7	0.5	0.5
RMPA	2.49	1.7	1.0	0.7	0.7
ARZ-NM	3.11	2.3	1.5	1.0	1.0
SOCAL-NEV	1.38	1.2	1.1	0.8	0.8
NOCAL-NEV	1.99	1.6	1.3	0.8	0.8
ALASKA	3.63	2.62	1.6	1.1	1.1
HAWAII	1.93	1.67	1.4	1.0	1.0

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

POPULATION
AVERAGE ANNUAL GROWTH RATES

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT I - 3

ELECTRIC POWER DEMAND
UNITED STATES SUMMARY
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	219170.	1.0	234210.	1.0	245826.	.7	254586.	.7	263710.	.8
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	10.1	4.0	13.3	3.3	15.7	3.5	18.6	3.3	21.8	3.6
TOTAL DEMAND(THOUSAND GWH)	2210.4	5.0	3110.1	4.3	3847.8	4.2	4727.4	4.0	5750.7	4.4
PEAK DEMAND(GW)	397.7	5.1	564.9	4.7	711.0	4.2	875.3	4.0	1066.5	4.6
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	10.1	2.7	12.1	2.6	13.8	2.6	15.6	2.6	17.8	2.6
TOTAL DEMAND(THOUSAND GWH)	2210.4	3.6	2836.9	3.6	3385.6	3.3	3983.9	3.3	4688.8	3.5
PEAK DEMAND(GW)	397.7	3.8	515.3	4.0	625.6	3.3	737.6	3.3	869.6	3.6
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	10.1	4.6	13.8	4.0	16.8	3.3	19.7	3.2	23.0	3.8
TOTAL DEMAND(THOUSAND GWH)	2210.4	5.5	3225.7	5.0	4119.6	4.0	5015.1	3.9	6077.2	4.7
PEAK DEMAND(GW)	397.7	5.7	585.9	5.4	761.2	4.1	928.6	3.9	1127.0	4.8
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	10.1	3.9	13.2	3.3	15.5	3.2	18.2	3.0	21.0	3.4
TOTAL DEMAND(THOUSAND GWH)	2210.4	4.9	3087.9	4.3	3819.0	3.9	4629.3	3.7	5550.9	4.3
PEAK DEMAND(GW)	397.7	5.0	560.9	4.7	705.7	4.0	857.2	3.7	1029.4	4.4
MARGIN(PERCENT)			28.4		24.9		24.1		23.8	
RESOURCES TO SERVE DEMAND(GW)			720.1		881.2		1063.9		1274.3	
LOAD FACTOR(PERCENT)	63.4		62.8		61.8		61.7		61.6	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

THE UNITED STATES

SHEET 1 OF 1

CONTRACT NO. DACW72 78 C 0013
DATE MARCH 1980

EXHIBIT I-4

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
EAST CENTRAL AREA RELIABILITY
COORDINATION AGREEMENT (ECAR)

SERVICE AREA APPROXIMATED BY BEA AREAS:

19	20	51	52	53	54	55	56	59	60
61	62	63	64	65	66	67	68	69	70
71	72	73	74	75	76				

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	2015.	2076.	2138.	2374.
MINING	1718.	1865.	2025.	2412.
CONSTRUCTION	8162.	9513.	11091.	15075.
MANUFACTURING	51119.	58649.	67334.	89277.
TRANSPO UTILITIES	8627.	10080.	11784.	16236.
TRADE	20309.	23379.	26924.	36395.
FINANCE	5940.	7264.	8888.	13103.
SERVICES	20971.	26149.	32611.	49927.
GOVERNMENT	18276.	22297.	27211.	40020.
TOTAL EARNINGS (MILLION $)	137147.	161390.	190017.	264830.
TOTAL PERSONAL INCOME (MILLION $)	171310.	202858.	240320.	338209.
TOTAL POPULATION (THOUSANDS)	36601.	38061.	39597.	41852.
PER CAPITA INCOME ($)	4681.	5330.	6069.	8081.
PER CAPTA INCOME RELATIVE TO U. S.	.98	.98	.98	.99

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: ECAR
SUB-REGION: ECAR

SHEET 1 OF 7

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT II-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT
ALLEGHENY POWER SYSTEM

SERVICE AREA APPROXIMATED BY BEA AREAS:
19 65 66

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	110.	111.	113.	123.
MINING	542.	582.	624.	734.
CONSTRUCTION	1075.	1216.	1377.	1792.
MANUFACTURING	5219.	5840.	6542.	8392.
TRANSPO UTILITIES	1226.	1395.	1588.	2100.
TRADE	2327.	2616.	2941.	3848.
FINANCE	659.	787.	941.	1345.
SERVICES	2729.	3308.	4012.	5889.
GOVERNMENT	1925.	2306.	2764.	3973.
TOTAL EARNINGS (MILLION $)	15813.	18178.	20903.	28197.
TOTAL PERSONAL INCOME (MILLION $)	20628.	23807.	27486.	37306.
TOTAL POPULATION (THOUSANDS)	4597.	4649.	4703.	4751.
PER CAPITA INCOME ($)	4487.	5121.	5845.	7852.
PER CAPTA INCOME RELATIVE TO U. S.	.94	.94	.95	.96

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: ECAR
SUB–REGION: APS

SHEET 2 OF 7

CONTRACT NO DACW72 – 78 – C – 0013
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EXHIBIT II–1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT
AMERICAN ELECTRIC POWER

SERVICE AREA APPROXIMATED BY BEA AREAS:
20 51 52 64 76

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	287.	294.	302.	333.
MINING	729.	796.	869.	1042.
CONSTRUCTION	1211.	1420.	1666.	2275.
MANUFACTURING	6247.	7307.	8552.	11622.
TRANSPU UTILITIES	1375.	1604.	1872.	2563.
TRADE	2823.	3283.	3820.	5221.
FINANCE	852.	1052.	1301.	1944.
SERVICES	2862.	3606.	4547.	7049.
GOVERNMENT	2699.	3312.	4068.	6008.
TOTAL EARNINGS (MILLION $)	19086.	22692.	26999.	38059.
TOTAL PERSONAL INCOME (MILLION $)	24134.	28845.	34503.	49044.
TOTAL POPULATION (THOUSANDS)	6025.	6266.	6522.	6842.
PER CAPITA INCOME ($)	4006.	4604.	5290.	7168.
PER CAPTA INCOME RELATIVE TO U. S.	.84	.85	.86	.88

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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PROJECTED POPULATION, INCOME & EARNINGS

REGION: ECAR
SUB-REGION: AEP

SHEET 3 OF 7

CONTRACT NO DACW72 - 78 - C - 0013
DATE MARCH 1980

EXHIBIT II-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT
CENTRAL AREA POWER COORDINATION GROUP

SERVICE AREA APPROXIMATED BY BEA AREAS:
67 68 70

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	253.	262.	270.	300.
MINING	98.	105.	112.	130.
CONSTRUCTION	1530.	1762.	2030.	2721.
MANUFACTURING	10655.	12036.	13599.	17674.
TRANSPO UTILITIES	1718.	1974.	2269.	3067.
TRADE	4004.	4536.	5140.	6808.
FINANCE	1112.	1341.	1618.	2344.
SERVICES	4218.	5186.	6377.	9586.
GOVERNMENT	2795.	3391.	4116.	6045.
TOTAL EARNINGS (MILLION $)	26384.	30616.	35531.	48677.
TOTAL PERSONAL INCOME (MILLION $)	32805.	38327.	44782.	61980.
TOTAL POPULATION (THOUSANDS)	6578.	6776.	6979.	7310.
PER CAPITA INCOME ($)	4987.	5657.	6416.	8479.
PER CAPTA INCOME RELATIVE TO U. S.	1.04	1.04	1.04	1.04

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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PROJECTED POPULATION, INCOME & EARNINGS

REGION: ECAR

SUB-REGION: CAPCO

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EXHIBIT II-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT
CINCINNATI COLUMBUS DAYTON GROUP

SERVICE AREA APPROXIMATED BY BEA AREAS:
62 63 69

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	234.	243.	252.	283.
MINING	16.	17.	17.	20.
CONSTRUCTION	804.	942.	1103.	1509.
MANUFACTURING	5129.	5888.	6759.	8954.
TRANSPO UTILITIES	868.	1026.	1214.	1701.
TRADE	2082.	2402.	2772.	3753.
FINANCE	635.	777.	951.	1402.
SERVICES	2196.	2748.	3437.	5279.
GOVERNMENT	2085.	2531.	3073.	4479.
TOTAL EARNINGS (MILLION $)	14050.	16586.	19580.	27381.
TOTAL PERSONAL INCOME (MILLION $)	17627.	20936.	24865.	35107.
TOTAL POPULATION (THOUSANDS)	3633.	3797.	3968.	4231.
PER CAPITA INCOME ($)	4852.	5514.	6266.	8298.
PER CAPTA INCOME RELATIVE TO U. S.	1.02	1.02	1.02	1.02

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: ECAR
SUB-REGION: CCD

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DATE: MARCH 1980

EXHIBIT II–1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT
KENTUCKY INDIANA

SERVICE AREA APPROXIMATED BY BEA AREAS:
53 54 55 56 59 60 61 75

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	838.	867.	898.	1002.
MINING	276.	304.	334.	405.
CONSTRUCTION	1451.	1726.	2052.	2859.
MANUFACTURING	8550.	10122.	11989.	16591.
TRANSPO UTILITIES	1475.	1750.	2077.	2923.
TRADE	3537.	4149.	4868.	6744.
FINANCE	1110.	1378.	1711.	2573.
SERVICES	3328.	4247.	5414.	8559.
GOVERNMENT	3557.	4370.	5370.	7959.
TOTAL EARNINGS (MILLION $)	24126.	28937.	34717.	49619.
TOTAL PERSONAL INCOME (MILLION $)	29700.	35877.	43352.	62657.
TOTAL POPULATION (THOUSANDS)	6757.	7137.	7541.	8153.
PER CAPITA INCOME ($)	4395.	5027.	5749.	7685.
PER CAPTA INCOME RELATIVE TO U. S.	.92	.93	.93	.94

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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PROJECTED POPULATION, INCOME & EARNINGS
REGION: ECAR
SUB-REGION: KY-IND
SHEET 6 OF 7

CONTRACT NO. DACW72 - 78 - C - 0013
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EXHIBIT II-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT
MICHIGAN ELECTRIC COORDINATED SYSTEM

SERVICE AREA APPROXIMATED BY BEA AREAS:
71 72 73 74

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	291.	297.	304.	333.
MINING	57.	62.	68.	82.
CONSTRUCTION	2091.	2447.	2864.	3919.
MANUFACTURING	15320.	17457.	19892.	26043.
TRANSPO UTILITIES	1965.	2331.	2765.	3882.
TRADE	5536.	6393.	7383.	10021.
FINANCE	1573.	1929.	2365.	3494.
SERVICES	5638.	7053.	8825.	13563.
GOVERNMENT	5215.	6386.	7820.	11557.
TOTAL EARNINGS (MILLION $)	37687.	44390.	52287.	72896.
TOTAL PERSONAL INCOME (MILLION $)	46417.	55067.	65331.	92114.
TOTAL POPULATION (THOUSANDS)	9010.	9437.	9884.	10565.
PER CAPITA INCOME ($)	5151.	5835.	6610.	8719.
PER CAPTA INCOME RELATIVE TO U. S.	1.08	1.07	1.07	1.07

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: ECAR
SUB-REGION: MECS

SHEET 7 OF 7

CONTRACT NO DACW72 - 78 - C - 0013
DATE MARCH 1980
EXHIBIT II-1

ELECTRIC POWER DEMAND
EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT(ECAR)
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	34824.	.6	36118.	.8	37541.	.6	38610.	.6	39716.	.6
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	10.7	3.9	13.9	3.8	16.8	3.9	20.3	2.9	23.4	3.6
TOTAL DEMAND(THOUSAND GWH)	369.1	4.5	503.1	4.6	629.8	4.5	785.2	3.5	930.4	4.3
PEAK DEMAND(GW)	63.3	4.9	88.2	4.6	110.6	4.5	137.9	3.5	163.4	4.4
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	10.7	2.6	12.8	2.6	14.5	2.6	16.5	2.6	18.8	2.6
TOTAL DEMAND(THOUSAND GWH)	369.1	3.2	460.8	3.4	544.6	3.2	636.8	3.2	744.7	3.2
PEAK DEMAND(GW)	63.3	3.5	80.8	3.4	95.6	3.2	111.8	3.2	130.8	3.4
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	10.7	4.5	14.5	4.0	17.7	3.3	20.8	3.2	24.3	3.8
TOTAL DEMAND(THOUSAND GWH)	369.1	5.1	524.0	4.8	662.6	3.9	801.6	3.8	965.2	4.5
PEAK DEMAND(GW)	63.3	5.5	91.9	4.8	116.4	3.9	140.8	3.8	169.5	4.6
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	10.7	3.9	13.9	3.8	16.8	3.9	20.3	2.9	23.4	3.6
TOTAL DEMAND(THOUSAND GWH)	369.1	4.5	503.1	4.6	629.8	4.5	785.2	3.5	930.4	4.3
PEAK DEMAND(GW)	63.3	4.9	88.2	4.6	110.6	4.5	137.9	3.5	163.4	4.4
MARGIN(PERCENT)			25.0		25.0		25.0		25.0	
RESOURCES TO SERVE DEMAND(GW)			110.2		138.3		172.4		204.3	
LOAD FACTOR(PERCENT)	66.6		65.1		65.0		65.0		65.0	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: ECAR
SUB-REGION: ECAR

SHEET 1 OF 7

CONTRACT NO. DACW72 78-C-0013
DATE: MARCH 1980

EXHIBIT II-2

ELECTRIC POWER DEMAND
ALLEGHENY POWER SYSTEM
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	4758.	.5	4927.	.2	4977.	.1	5002.	.1	5027.	.3
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	6.5	4.7	9.0	4.8	11.3	4.9	14.4	4.8	18.2	4.8
TOTAL DEMAND(THOUSAND GWH)	30.9	5.2	44.1	5.0	56.3	5.0	71.9	4.9	91.4	5.1
PEAK DEMAND(GW)	5.2	6.2	7.9	5.0	10.1	5.0	12.9	4.9	16.4	5.4
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	6.5	2.6	7.8	2.6	8.8	2.6	10.0	2.6	11.4	2.6
TOTAL DEMAND(THOUSAND GWH)	30.9	3.1	38.3	2.8	44.0	2.7	50.3	2.7	57.4	2.9
PEAK DEMAND(GW)	5.2	4.0	6.9	2.8	7.9	2.7	9.0	2.7	10.3	3.2
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	6.5	4.5	8.8	4.0	10.8	3.3	12.6	3.2	14.8	3.8
TOTAL DEMAND(THOUSAND GWH)	30.9	5.0	43.5	4.2	53.5	3.4	63.3	3.3	74.4	4.1
PEAK DEMAND(GW)	5.2	6.0	7.8	4.3	9.6	3.4	11.4	3.3	13.4	4.4
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	6.5	4.5	8.8	4.0	10.8	3.3	12.6	3.2	14.8	3.8
TOTAL DEMAND(THOUSAND GWH)	30.9	5.0	43.5	4.2	53.5	3.4	63.3	3.3	74.4	4.1
PEAK DEMAND(GW)	5.2	6.0	7.8	4.3	9.6	3.4	11.4	3.3	13.4	4.4
MARGIN(PERCENT)			25.0		25.0		20.0		20.0	
RESOURCES TO SERVE DEMAND(GW)			9.8		12.0		13.6		16.0	
LOAD FACTOR(PERCENT)	67.8		63.7		63.6		63.6		63.6	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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OF NEED FOR HYDROPOWER
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PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: ECAR
SUB-REGION: APS

SHEET 2 OF 7

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT II-2

ELECTRIC POWER DEMAND
AMERICAN ELECTRIC POWER SYSTEM
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	5518.	.5	5714.	.8	5946.	.5	6096.	.5	6250.	.6
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	13.4	4.2	17.9	3.4	21.2	3.5	25.1	3.5	29.9	3.7
TOTAL DEMAND(THOUSAND GWH)	73.9	4.8	102.4	4.2	126.0	4.0	153.3	4.0	186.8	4.3
PEAK DEMAND(GW)	13.1	4.7	18.1	4.2	22.2	4.0	27.0	4.0	32.9	4.3
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	13.4	2.6	16.0	2.6	18.2	2.6	20.7	2.6	23.6	2.6
TOTAL DEMAND(THOUSAND GWH)	73.9	3.1	91.6	3.4	108.4	3.1	126.3	3.1	147.2	3.2
PEAK DEMAND(GW)	13.1	3.1	16.2	3.4	19.1	3.1	22.3	3.1	25.9	3.2
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	13.4	4.5	18.2	4.0	22.2	3.3	26.1	3.2	30.5	3.8
TOTAL DEMAND(THOUSAND GWH)	73.9	5.0	104.1	4.8	131.8	3.8	159.0	3.7	190.8	4.4
PEAK DEMAND(GW)	13.1	5.0	18.4	4.8	23.2	3.8	28.0	3.7	33.6	4.4
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	13.4	4.2	17.9	3.4	21.2	3.5	25.1	3.5	29.9	3.7
TOTAL DEMAND(THOUSAND GWH)	73.9	4.8	102.4	4.2	126.0	4.0	153.3	4.0	186.8	4.3
PEAK DEMAND(GW)	13.1	4.7	18.1	4.2	22.2	4.0	27.0	4.0	32.9	4.3
MARGIN(PERCENT)			20.0		20.0		20.0		20.0	
RESOURCES TO SERVE DEMAND(GW)			21.7		26.6		32.4		39.5	
LOAD FACTOR(PERCENT)	54.4		64.6		64.8		64.8		64.8	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: ECAR
SUB-REGION: AEP

SHEET 3 OF 7

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT II-2

ELECTRIC POWER DEMAND
CENTRAL AREA POWER COORDINATION GROUP
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	6156.	.4	6330.	.6	6523.	.5	6687.	.5	6856.	.5
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	10.3	3.2	12.9	2.4	14.5	2.8	16.7	2.8	19.1	2.8
TOTAL DEMAND(THOUSAND GWH)	63.7	3.6	81.8	3.0	94.8	3.3	111.5	3.3	131.0	3.3
PEAK DEMAND(GW)	11.0	3.7	14.2	3.0	16.5	3.3	19.4	3.3	22.8	3.4
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	10.3	2.6	12.4	2.6	14.1	2.6	16.0	2.6	18.2	2.6
TOTAL DEMAND(THOUSAND GWH)	63.7	3.0	78.4	3.2	91.8	3.1	107.0	3.1	124.8	3.1
PEAK DEMAND(GW)	11.0	3.1	13.6	3.3	16.0	3.1	18.6	3.1	21.7	3.1
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	10.3	4.5	14.1	4.0	17.1	3.3	20.2	3.2	23.6	3.8
TOTAL DEMAND(THOUSAND GWH)	63.7	4.9	89.1	4.6	111.8	3.8	134.8	3.7	161.7	4.3
PEAK DEMAND(GW)	11.0	5.0	15.5	4.7	19.4	3.8	23.5	3.7	28.1	4.4
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	10.3	3.2	12.9	2.4	14.5	2.6	16.7	2.8	19.1	2.8
TOTAL DEMAND(THOUSAND GWH)	63.7	3.6	81.8	3.0	94.8	3.3	111.5	3.3	131.0	3.3
PEAK DEMAND(GW)	11.0	3.7	14.2	3.0	16.5	3.3	19.4	3.3	22.8	3.4
MARGIN(PERCENT)			25.0		25.0		21.0		21.0	
RESOURCES TO SERVE DEMAND(GW)			17.7		20.6		23.5		27.6	
LOAD FACTOR(PERCENT)	66.1		65.8		65.6		65.6		65.6	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: ECAR
SUB-REGION: CAPCO

SHEET 4 OF 7

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT II-2

ELECTRIC POWER DEMAND
CINCINNATI COLUMBUS DAYTON GROUP
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	3365.	.5	3485.	.9	3645.	.6	3755.	.6	3869.	.6
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	10.3	4.3	13.9	4.6	17.4	3.9	21.1	3.5	25.1	4.1
TOTAL DEMAND(THOUSAND GWH)	34.7	4.9	48.4	5.6	63.4	4.6	79.3	4.2	97.2	4.8
PEAK DEMAND(GW)	6.8	4.9	9.5	5.5	12.4	4.6	15.5	4.2	19.0	4.8
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	10.3	2.6	12.3	2.6	14.0	2.6	16.0	2.6	18.1	2.6
TOTAL DEMAND(THOUSAND GWH)	34.7	3.1	43.0	3.5	51.1	3.2	59.9	3.2	70.2	3.3
PEAK DEMAND(GW)	6.8	3.1	8.4	3.4	10.0	3.2	11.7	3.2	13.7	3.2
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	10.3	4.5	14.0	4.0	17.1	3.3	20.1	3.2	23.5	3.8
TOTAL DEMAND(THOUSAND GWH)	34.7	5.0	48.9	4.9	62.2	3.9	75.4	3.8	91.0	4.5
PEAK DEMAND(GW)	6.8	5.0	9.6	4.9	12.2	3.9	14.7	3.8	17.8	4.5
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	10.3	4.3	13.9	4.2	17.1	3.3	20.1	3.2	23.5	3.8
TOTAL DEMAND(THOUSAND GWH)	34.7	4.9	48.4	5.2	62.2	3.9	75.4	3.8	91.0	4.5
PEAK DEMAND(GW)	6.8	4.9	9.5	5.1	12.2	3.9	14.7	3.8	17.8	4.5
MARGIN(PERCENT)			23.0		23.0		23.0		23.0	
RESOURCES TO SERVE DEMAND(GW)			11.7		15.0		18.1		21.9	
LOAD FACTOR(PERCENT)	58.3		58.2		58.4		58.4		58.4	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: ECAR
SUB-REGION: CCD

SHEET 5 OF 7

CONTRACT NO. DACW72-78-C-0013
DATE: MARCH 1980

EXHIBIT II-2

ELECTRIC POWER DEMAND
KENTUCKY-INDIANA GROUP
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	6352.	.9	6763.	1.1	7143.	.8	7433.	.8	7735.	.9
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	12.6	4.5	17.1	4.6	21.4	4.9	27.2	4.3	33.7	4.6
TOTAL DEMAND(THOUSAND GWH)	79.9	5.4	115.7	5.7	153.0	5.8	202.4	5.2	260.6	5.5
PEAK DEMAND(GW)	14.7	6.1	22.3	5.9	29.7	5.8	39.3	5.2	50.6	5.8
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	12.6	2.6	15.1	2.6	17.1	2.6	19.5	2.6	22.1	2.6
TOTAL DEMAND(THOUSAND GWH)	79.9	3.5	101.8	3.7	122.3	3.4	144.6	3.4	171.1	3.5
PEAK DEMAND(GW)	14.7	4.2	19.6	3.9	23.7	3.4	28.1	3.4	33.2	3.8
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	12.6	4.5	17.1	4.0	20.8	3.3	24.5	3.2	28.7	3.8
TOTAL DEMAND(THOUSAND GWH)	79.9	5.4	115.8	5.1	148.8	4.1	182.1	4.0	221.6	4.8
PEAK DEMAND(GW)	14.7	6.1	22.3	5.3	28.9	4.1	35.4	4.0	43.1	5.0
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	12.6	4.5	17.1	4.0	20.8	3.3	24.5	3.2	28.7	3.8
TOTAL DEMAND(THOUSAND GWH)	79.9	5.4	115.7	5.2	148.8	4.1	182.1	4.0	221.8	4.8
PEAK DEMAND(GW)	14.7	6.1	22.3	5.3	28.9	4.1	35.4	4.0	43.1	5.0
MARGIN(PERCENT)			25.0		20.0		20.0		20.0	
RESOURCES TO SERVE DEMAND(GW)			27.9		34.7		42.4		51.7	
LOAD FACTOR(PERCENT)	62.0		59.2		58.8		58.8		58.8	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: ECAR

SUB-REGION: KY-IND

SHEET 6 OF 7

CONTRACT NO. DACW72-78-C-0013

DATE: MARCH 1980

EXHIBIT II-2

ELECTRIC POWER DEMAND
MICHIGAN-ELECTRIC COORDINATED SYSTEM
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	8475.	.7	8899.	.9	9307.	.7	9637.	.7	9979.	.7
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	8.0	2.3	9.3	2.3	10.5	2.1	11.6	2.0	12.9	2.2
TOTAL DEMAND(THOUSAND GWH)	67.4	3.0	83.0	3.3	97.4	2.8	112.1	2.8	128.4	3.0
PEAK DEMAND(GW)	11.9	3.1	14.7	3.3	17.3	2.8	19.9	2.8	22.8	3.0
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	8.0	2.6	9.5	2.6	10.8	2.6	12.3	2.6	14.0	2.6
TOTAL DEMAND(THOUSAND GWH)	67.4	3.3	84.7	3.5	100.7	3.3	118.6	3.3	139.6	3.4
PEAK DEMAND(GW)	11.9	3.4	15.0	3.6	17.9	3.3	21.0	3.3	24.8	3.4
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	8.0	4.5	10.8	4.0	13.2	3.3	15.5	3.2	18.1	3.8
TOTAL DEMAND(THOUSAND GWH)	67.4	5.2	96.3	4.9	122.5	4.0	149.3	3.9	180.9	4.6
PEAK DEMAND(GW)	11.9	5.3	17.1	5.0	21.8	4.0	26.5	3.9	32.1	4.6
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	8.0	2.6	9.5	2.6	10.8	2.6	12.3	2.6	14.0	2.6
TOTAL DEMAND(THOUSAND GWH)	67.4	3.3	84.7	3.5	100.7	3.3	118.6	3.3	139.6	3.4
PEAK DEMAND(GW)	11.9	3.4	15.0	3.6	17.9	3.3	21.0	3.3	24.8	3.4
MARGIN(PERCENT)			25.0		25.0		25.0		25.0	
RESOURCES TO SERVE DEMAND(GW)			18.8		22.4		26.3		31.0	
LOAD FACTOR(PERCENT)	64.7		64.5		64.3		64.3		64.3	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: ECAR
SUB-REGION: MECS

SHEET 7 OF 7

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT II-2

ECAR AEP AMERICAN ELECTRIC POWER SYSTEM

YEAR: 1985
WEEKLY LOAD FACTOR: OFF-SEASON 65.3
SUMMER 67.0
WINTER 81.4

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO (PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	82.1	83.7	96.2	.013	.019	.033	.013	.021	.034
1.0 - 2.0	81.1	82.7	95.2	.028	.040	.049	.033	.065	.075
2.0 - 3.0	80.1	81.7	94.2	.030	.068	.070	.067	.168	.147
3.0 - 4.0	79.1	80.7	93.2	.036	.070	.090	.101	.224	.198
4.0 - 5.0	78.1	79.7	92.2	.046	.080	.092	.173	.279	.218
5.0 - 6.0	77.1	78.7	91.2	.062	.090	.111	.232	.325	.261
6.0 - 7.0	76.1	77.7	90.2	.070	.096	.126	.339	.374	.349
7.0 - 8.0	75.1	76.7	89.2	.070	.120	.132	.410	.437	.454
8.0 - 9.0	74.1	75.7	88.2	.079	.130	.146	.474	.513	.593
9.0 - 10.0	73.1	74.7	87.2	.080	.130	.158	.490	.561	.676
10.0 - 11.0	72.1	73.7	86.2	.091	.130	.170	.518	.590	.745
11.0 - 12.0	71.1	72.7	85.2	.113	.139	.170	.558	.614	.802
12.0 - 13.0	70.1	71.7	84.2	.142	.145	.170	.605	.642	.830
13.0 - 14.0	69.1	70.7	83.2	.160	.150	.170	.653	.665	.875
14.0 - 15.0	68.1	69.7	82.2	.160	.150	.170	.673	.721	.927
15.0 - 16.0	67.1	68.7	81.2	.160	.150	.177	.694	.730	.958
16.0 - 17.0	66.1	67.7	80.2	.161	.150	.190	.724	.738	.996
17.0 - 18.0	65.1	66.7	79.2	.179	.154	.190	.770	.744	1.005
18.0 - 19.0	64.1	65.7	78.2	.186	.160	.202	.814	.788	1.054
19.0 - 20.0	63.1	64.7	77.2	.205	.170	.232	.879	.838	1.108
20.0 - 21.0	62.1	63.7	76.2	.230	.170	.240	.961	.913	1.146
21.0 - 22.0	61.1	62.7	75.2	.230	.170	.240	1.024	.962	1.211
22.0 - 23.0	60.1	61.7	74.2	.230	.175	.240	1.063	1.024	1.231
23.0 - 24.0	59.1	60.7	73.2	.237	.180	.240	1.101	1.106	1.248
24.0 - 25.0	58.1	59.7	72.2	.240	.180	.240	1.157	1.130	1.250
25.0 - 26.0	57.1	58.7	71.2	.240	.187	.240	1.177	1.164	1.263
26.0 - 27.0	56.1	57.7	70.2	.240	.198	.240	1.233	1.210	1.286
27.0 - 28.0	55.1	56.7	69.2	.240	.200	.240	1.305	1.265	1.325
28.0 - 29.0	54.1	55.7	68.2	.240	.211	.240	1.383	1.315	1.348
29.0 - 30.0	53.1	54.7	67.2	.240	.223	.240	1.473	1.387	1.384
30.0 - 31.0	52.1	53.7	66.2	.240	.240	.240	1.565	1.448	1.441
31.0 - 32.0	51.1	52.7	65.2	.240	.240	.240	1.593	1.518	1.466
32.0 - 33.0	50.1	51.7	64.2	.240	.240	.240	1.600	1.565	1.500
33.0 - 34.0	49.1	50.7	63.2	.240	.240	.240	1.603	1.574	1.540
34.0 - 35.0	48.1	49.7	62.2	.240	.240	.240	1.611	1.600	1.569
35.0 - 36.0	47.1	48.7	61.2	.240	.240	.240	1.620	1.638	1.592
36.0 - 37.0	46.1	47.7	60.2	.240	.240	.240	1.628	1.662	1.620
37.0 - 38.0	45.1	46.7	59.2	.240	.240	.240	1.651	1.680	1.636
38.0 - 39.0	44.1	45.7	58.2	.240	.240	.240	1.669	1.680	1.652
39.0 - 40.0	43.1	44.7	57.2	.240	.240	.240	1.680	1.680	1.673
40.0 - 41.0	42.1	43.7	56.2	.240	.240	.240	1.680	1.680	1.680
41.0 - 42.0	41.1	42.7	55.2	.240	.240	.240	1.680	1.680	1.680

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: ECAR
SUB-REGION: AEP
UTILITY: AEP

SHEET 1 OF 7

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT II-3

ECAR CAPCO DUQUESNE LIGHT COMPANY

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 62.7
SUMMER 69.2
WINTER 71.0

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	80.4	90.4	87.1	.010	.020	.026	.010	.020	.026
1.0 - 2.0	79.4	89.4	86.1	.028	.033	.045	.061	.040	.048
2.0 - 3.0	78.4	88.4	85.1	.044	.051	.084	.127	.073	.112
3.0 - 4.0	77.4	87.4	84.1	.072	.060	.100	.189	.114	.167
4.0 - 5.0	76.4	86.4	83.1	.090	.065	.114	.306	.183	.315
5.0 - 6.0	75.4	85.4	82.1	.109	.072	.129	.428	.215	.455
6.0 - 7.0	74.4	84.4	81.1	.118	.080	.140	.493	.248	.539
7.0 - 8.0	73.4	83.4	80.1	.123	.080	.140	.516	.269	.595
8.0 - 9.0	72.4	82.4	79.1	.135	.098	.140	.547	.332	.634
9.0 - 10.0	71.4	81.4	78.1	.140	.119	.140	.571	.397	.650
10.0 - 11.0	70.4	80.4	77.1	.140	.128	.147	.580	.457	.685
11.0 - 12.0	69.4	79.4	76.1	.140	.130	.160	.588	.497	.704
12.0 - 13.0	68.4	78.4	75.1	.140	.138	.160	.595	.559	.733
13.0 - 14.0	67.4	77.4	74.1	.150	.140	.160	.610	.595	.770
14.0 - 15.0	66.4	76.4	73.1	.159	.141	.160	.632	.604	.780
15.0 - 16.0	65.4	75.4	72.1	.160	.150	.164	.648	.640	.795
16.0 - 17.0	64.4	74.4	71.1	.160	.150	.170	.690	.659	.837
17.0 - 18.0	63.4	73.4	70.1	.160	.150	.170	.709	.679	.870
18.0 - 19.0	62.4	72.4	69.1	.160	.158	.170	.747	.696	.915
19.0 - 20.0	61.4	71.4	68.1	.165	.160	.170	.762	.720	.946
20.0 - 21.0	60.4	70.4	67.1	.190	.160	.180	.822	.742	.986
21.0 - 22.0	59.4	69.4	66.1	.193	.160	.180	.868	.768	1.003
22.0 - 23.0	58.4	68.4	65.1	.209	.160	.180	.899	.780	1.023
23.0 - 24.0	57.4	67.4	64.1	.217	.166	.190	.941	.810	1.058
24.0 - 25.0	56.4	66.4	63.1	.238	.175	.208	1.016	.866	1.104
25.0 - 26.0	55.4	65.4	62.1	.240	.180	.221	1.086	.897	1.164
26.0 - 27.0	54.4	64.4	61.1	.240	.180	.234	1.137	.917	1.231
27.0 - 28.0	53.4	63.4	60.1	.240	.180	.240	1.201	.955	1.292
28.0 - 29.0	52.4	62.4	59.1	.240	.191	.240	1.280	.989	1.357
29.0 - 30.0	51.4	61.4	58.1	.240	.200	.240	1.347	1.057	1.415
30.0 - 31.0	50.4	60.4	57.1	.240	.203	.240	1.385	1.113	1.439
31.0 - 32.0	49.4	59.4	56.1	.240	.210	.240	1.428	1.173	1.457
32.0 - 33.0	48.4	58.4	55.1	.240	.226	.240	1.467	1.224	1.466
33.0 - 34.0	47.4	57.4	54.1	.240	.240	.240	1.520	1.317	1.504
34.0 - 35.0	46.4	56.4	53.1	.240	.240	.240	1.571	1.369	1.520
35.0 - 36.0	45.4	55.4	52.1	.240	.240	.240	1.592	1.429	1.527
36.0 - 37.0	44.4	54.4	51.1	.240	.240	.240	1.600	1.447	1.555
37.0 - 38.0	43.4	53.4	50.1	.240	.240	.240	1.608	1.463	1.574
38.0 - 39.0	42.4	52.4	49.1	.240	.240	.240	1.617	1.490	1.605
39.0 - 40.0	41.4	51.4	48.1	.240	.240	.240	1.626	1.523	1.619
40.0 - 41.0	40.4	50.4	47.1	.240	.240	.240	1.643	1.564	1.631
41.0 - 42.0	39.4	49.4	46.1	.240	.240	.240	1.674	1.596	1.656
42.0 - 43.0	38.4	48.4	45.1	.240	.240	.240	1.680	1.622	1.677
43.0 - 44.0	37.4	47.4	44.1	.240	.240	.240	1.680	1.633	1.680
44.0 - 45.0	36.4	46.4	43.1	.240	.240	.240	1.680	1.651	1.680
45.0 - 46.0	35.4	45.4	42.1	.240	.240	.240	1.680	1.667	1.680

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: ECAR
SUB-REGION: CAPCO
UTILITY: DLCO

SHEET 2 OF 7

CONTRACT NO. DACW72 78 C 0013
DATE: MARCH 1980

EXHIBIT II-3

ECAR CAPCO OHIO EDISON COMPANY

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 61.9
SUMMER 68.5
WINTER 73.8

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	80.4	90.6	92.5	.010	.021	.010	.013	.021	.012
1.0 - 2.0	79.4	89.6	91.5	.011	.037	.018	.051	.037	.046
2.0 - 3.0	78.4	88.6	90.5	.035	.050	.027	.170	.052	.086
3.0 - 4.0	77.4	87.6	89.5	.049	.058	.035	.216	.082	.118
4.0 - 5.0	76.4	86.6	88.5	.050	.067	.040	.284	.128	.179
5.0 - 6.0	75.4	85.6	87.5	.065	.079	.040	.361	.192	.255
6.0 - 7.0	74.4	84.6	86.5	.091	.096	.044	.452	.283	.365
7.0 - 8.0	73.4	83.6	85.5	.110	.100	.069	.514	.323	.473
8.0 - 9.0	72.4	82.6	84.5	.114	.117	.099	.524	.367	.537
9.0 - 10.0	71.4	81.6	83.5	.141	.123	.125	.560	.406	.626
10.0 - 11.0	70.4	80.6	82.5	.150	.130	.130	.597	.459	.650
11.0 - 12.0	69.4	79.6	81.5	.150	.130	.137	.600	.522	.677
12.0 - 13.0	68.4	78.6	80.5	.150	.130	.141	.614	.576	.716
13.0 - 14.0	67.4	77.6	79.5	.157	.131	.150	.627	.609	.742
14.0 - 15.0	66.4	76.6	78.5	.160	.140	.159	.630	.637	.771
15.0 - 16.0	65.4	75.6	77.5	.160	.144	.160	.650	.658	.781
16.0 - 17.0	64.4	74.6	76.5	.160	.150	.160	.680	.674	.800
17.0 - 18.0	63.4	73.6	75.5	.160	.150	.160	.709	.690	.813
18.0 - 19.0	62.4	72.6	74.5	.166	.150	.160	.744	.706	.831
19.0 - 20.0	61.4	71.6	73.5	.170	.150	.167	.760	.739	.912
20.0 - 21.0	60.4	70.6	72.5	.170	.150	.170	.780	.757	.943
21.0 - 22.0	59.4	69.6	71.5	.182	.162	.170	.821	.775	.960
22.0 - 23.0	58.4	68.6	70.5	.190	.170	.170	.878	.799	.972
23.0 - 24.0	57.4	67.6	69.5	.200	.170	.170	.919	.812	.993
24.0 - 25.0	56.4	66.6	68.5	.207	.170	.172	.952	.820	1.012
25.0 - 26.0	55.4	65.6	67.5	.217	.170	.180	1.018	.833	1.043
26.0 - 27.0	54.4	64.6	66.5	.232	.172	.180	1.071	.859	1.055
27.0 - 28.0	53.4	63.6	65.5	.240	.180	.180	1.112	.890	1.093
28.0 - 29.0	52.4	62.6	64.5	.240	.180	.180	1.162	.942	1.136
29.0 - 30.0	51.4	61.6	63.5	.240	.180	.183	1.199	.984	1.198
30.0 - 31.0	50.4	60.6	62.5	.240	.185	.190	1.244	1.028	1.269
31.0 - 32.0	49.4	59.6	61.5	.240	.191	.190	1.315	1.073	1.285
32.0 - 33.0	48.4	58.6	60.5	.240	.200	.190	1.385	1.121	1.301
33.0 - 34.0	47.4	57.6	59.5	.240	.204	.194	1.458	1.168	1.343
34.0 - 35.0	46.4	56.6	58.5	.240	.210	.208	1.501	1.230	1.387
35.0 - 36.0	45.4	55.6	57.5	.240	.227	.218	1.547	1.311	1.398
36.0 - 37.0	44.4	54.6	56.5	.240	.240	.240	1.590	1.361	1.440
37.0 - 38.0	43.4	53.6	55.5	.240	.240	.240	1.593	1.437	1.461
38.0 - 39.0	42.4	52.6	54.5	.240	.240	.240	1.606	1.450	1.488
39.0 - 40.0	41.4	51.6	53.5	.240	.240	.240	1.610	1.462	1.516
40.0 - 41.0	40.4	50.6	52.5	.240	.240	.240	1.610	1.476	1.538
41.0 - 42.0	39.4	49.6	51.5	.240	.240	.240	1.617	1.522	1.588
42.0 - 43.0	38.4	48.6	50.5	.240	.240	.240	1.632	1.538	1.596
43.0 - 44.0	37.4	47.6	49.5	.240	.240	.240	1.654	1.559	1.605
44.0 - 45.0	36.4	46.6	48.5	.240	.240	.240	1.678	1.577	1.610
45.0 - 46.0	35.4	45.6	47.5	.240	.240	.240	1.680	1.610	1.618

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THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: EACR
SUB-REGION: CAPCO
UTILITY: OE

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT II-3

ECAR APS WEST PENNSYLVANIA POWER COMPANY AND SUBSIDIARIES

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 68.3
SUMMER 66.3
WINTER 79.1

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	86.7	84.7	98.3	.010	.018	.010	.010	.022	.010
1.0 - 2.0	85.7	83.7	97.3	.010	.021	.014	.017	.062	.018
2.0 - 3.0	84.7	82.7	96.3	.027	.043	.020	.062	.145	.040
3.0 - 4.0	83.7	81.7	95.3	.065	.060	.025	.150	.211	.055
4.0 - 5.0	82.7	80.7	94.3	.092	.068	.030	.244	.286	.079
5.0 - 6.0	81.7	79.7	93.3	.124	.071	.030	.331	.340	.116
6.0 - 7.0	80.7	78.7	92.3	.130	.097	.031	.391	.414	.163
7.0 - 8.0	79.7	77.7	91.3	.130	.100	.049	.447	.484	.224
8.0 - 9.0	78.7	76.7	90.3	.141	.103	.066	.514	.527	.282
9.0 - 10.0	77.7	75.7	89.3	.150	.125	.097	.538	.565	.379
10.0 - 11.0	76.7	74.7	88.3	.150	.130	.125	.557	.590	.484
11.0 - 12.0	75.7	73.7	87.3	.154	.131	.130	.584	.622	.575
12.0 - 13.0	74.7	72.7	86.3	.160	.140	.130	.601	.656	.650
13.0 - 14.0	73.7	71.7	85.3	.160	.140	.138	.610	.668	.705
14.0 - 15.0	72.7	70.7	84.3	.160	.148	.140	.632	.693	.760
15.0 - 16.0	71.7	69.7	83.3	.162	.150	.150	.654	.732	.818
16.0 - 17.0	70.7	68.7	82.3	.170	.150	.150	.705	.750	.843
17.0 - 18.0	69.7	67.7	81.3	.170	.150	.150	.724	.750	.865
18.0 - 19.0	68.7	66.7	80.3	.170	.150	.150	.749	.756	.893
19.0 - 20.0	67.7	65.7	79.3	.172	.155	.150	.769	.779	.901
20.0 - 21.0	66.7	64.7	78.3	.180	.160	.168	.811	.810	.939
21.0 - 22.0	65.7	63.7	77.3	.180	.160	.170	.846	.837	.969
22.0 - 23.0	64.7	62.7	76.3	.180	.160	.170	.888	.861	.990
23.0 - 24.0	63.7	61.7	75.3	.182	.166	.170	.907	.898	1.001
24.0 - 25.0	62.7	60.7	74.3	.190	.170	.170	.966	.945	1.010
25.0 - 26.0	61.7	59.7	73.3	.198	.170	.170	1.049	.970	1.014
26.0 - 27.0	60.7	58.7	72.3	.231	.170	.172	1.124	1.006	1.052
27.0 - 28.0	59.7	57.7	71.3	.240	.170	.180	1.168	1.061	1.119
28.0 - 29.0	58.7	56.7	70.3	.240	.170	.180	1.217	1.135	1.179
29.0 - 30.0	57.7	55.7	69.3	.240	.172	.188	1.264	1.200	1.245
30.0 - 31.0	56.7	54.7	68.3	.240	.180	.190	1.319	1.256	1.284
31.0 - 32.0	55.7	53.7	67.3	.240	.180	.190	1.385	1.350	1.314
32.0 - 33.0	54.7	52.7	66.3	.240	.194	.207	1.437	1.423	1.352
33.0 - 34.0	53.7	51.7	65.3	.240	.216	.210	1.513	1.495	1.371
34.0 - 35.0	52.7	50.7	64.3	.240	.221	.210	1.559	1.511	1.406
35.0 - 36.0	51.7	49.7	63.3	.240	.240	.218	1.589	1.530	1.432
36.0 - 37.0	50.7	48.7	62.3	.240	.240	.227	1.600	1.537	1.471
37.0 - 38.0	49.7	47.7	61.3	.240	.240	.240	1.609	1.569	1.505
38.0 - 39.0	48.7	46.7	60.3	.240	.240	.240	1.611	1.571	1.568
39.0 - 40.0	47.7	45.7	59.3	.240	.240	.240	1.620	1.599	1.593
40.0 - 41.0	46.7	44.7	58.3	.240	.240	.240	1.621	1.623	1.600
41.0 - 42.0	45.7	43.7	57.3	.240	.240	.240	1.640	1.652	1.610
42.0 - 43.0	44.7	42.7	56.3	.240	.240	.240	1.658	1.680	1.617
43.0 - 44.0	43.7	41.7	55.3	.240	.240	.240	1.679	1.680	1.621
44.0 - 45.0	42.7	40.7	54.3	.240	.240	.240	1.680	1.680	1.646
45.0 - 46.0	41.7	39.7	53.3	.240	.240	.240	1.680	1.680	1.662

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: ECAR
SUB-REGION: APS
UTILITY: WEPP

SHEET 4 OF 7

CONTRACT NO. DACW72 - 78 - C - 0013

DATE MARCH 1980

EXHIBIT II-3

ECAR CCD THE CINCINNATI GAS + ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 50.4
SUMMER 62.8
WINTER 67.1

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO (PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	65.6	83.8	85.7	.022	.013	.018	.022	.023	.018
1.0 - 2.0	64.6	82.8	84.7	.044	.030	.029	.050	.056	.030
2.0 - 3.0	63.6	81.8	83.7	.055	.040	.030	.101	.092	.040
3.0 - 4.0	62.6	80.8	82.7	.091	.044	.037	.170	.104	.060
4.0 - 5.0	61.6	79.8	81.7	.103	.050	.046	.236	.126	.081
5.0 - 6.0	60.6	78.8	80.7	.133	.055	.050	.318	.160	.133
6.0 - 7.0	59.6	77.8	79.7	.140	.065	.050	.415	.207	.192
7.0 - 8.0	58.6	76.8	78.7	.144	.070	.058	.451	.246	.249
8.0 - 9.0	57.6	75.8	77.7	.153	.070	.069	.484	.258	.309
9.0 - 10.0	56.6	74.8	76.7	.160	.079	.098	.526	.310	.397
10.0 - 11.0	55.6	73.8	75.7	.160	.090	.115	.558	.369	.500
11.0 - 12.0	54.6	72.8	74.7	.160	.099	.123	.588	.432	.537
12.0 - 13.0	53.6	71.8	73.7	.160	.110	.130	.612	.478	.603
13.0 - 14.0	52.6	70.8	72.7	.164	.111	.143	.649	.495	.664
14.0 - 15.0	51.6	69.8	71.7	.170	.120	.157	.686	.523	.743
15.0 - 16.0	50.6	68.8	70.7	.180	.125	.160	.734	.559	.804
16.0 - 17.0	49.6	67.8	69.7	.180	.130	.160	.762	.599	.858
17.0 - 18.0	48.6	66.8	68.7	.182	.130	.161	.825	.613	.875
18.0 - 19.0	47.6	65.8	67.7	.190	.138	.170	.896	.645	.925
19.0 - 20.0	46.6	64.8	66.7	.192	.140	.170	.975	.687	.967
20.0 - 21.0	45.6	63.8	65.7	.204	.144	.170	1.050	.732	.975
21.0 - 22.0	44.6	62.8	64.7	.222	.150	.170	1.113	.783	1.012
22.0 - 23.0	43.6	61.8	63.7	.240	.150	.170	1.175	.828	1.051
23.0 - 24.0	42.6	60.8	62.7	.240	.150	.170	1.246	.885	1.083
24.0 - 25.0	41.6	59.8	61.7	.240	.150	.170	1.342	.965	1.107
25.0 - 26.0	40.6	58.8	60.7	.240	.160	.173	1.409	1.033	1.134
26.0 - 27.0	39.6	57.8	59.7	.240	.160	.180	1.472	1.078	1.157
27.0 - 28.0	38.6	56.8	58.7	.240	.169	.180	1.499	1.114	1.207
28.0 - 29.0	37.6	55.8	57.7	.240	.180	.180	1.533	1.137	1.249
29.0 - 30.0	36.6	54.8	56.7	.240	.180	.180	1.565	1.143	1.290
30.0 - 31.0	35.6	53.8	55.7	.240	.180	.180	1.572	1.188	1.317
31.0 - 32.0	34.6	52.8	54.7	.240	.180	.180	1.610	1.247	1.330
32.0 - 33.0	33.6	51.8	53.7	.240	.187	.181	1.635	1.264	1.332
33.0 - 34.0	32.6	50.8	52.7	.240	.200	.200	1.656	1.286	1.374
34.0 - 35.0	31.6	49.8	51.7	.240	.200	.210	1.679	1.348	1.420
35.0 - 36.0	30.6	48.8	50.7	.240	.200	.223	1.680	1.376	1.438
36.0 - 37.0	29.6	47.8	49.7	.240	.210	.235	1.680	1.438	1.488
37.0 - 38.0	28.6	46.8	48.7	.240	.233	.240	1.680	1.502	1.537
38.0 - 39.0	27.6	45.8	47.7	.240	.240	.240	1.680	1.553	1.540
39.0 - 40.0	26.6	44.8	46.7	.240	.240	.240	1.680	1.592	1.556
40.0 - 41.0	25.6	43.8	45.7	.240	.240	.240	1.680	1.615	1.579
41.0 - 42.0	24.6	42.8	44.7	.240	.240	.240	1.680	1.638	1.600
42.0 - 43.0	23.6	41.8	43.7	.240	.240	.240	1.680	1.651	1.621
43.0 - 44.0	22.6	40.8	42.7	.240	.240	.240	1.680	1.674	1.632
44.0 - 45.0	21.6	39.8	41.7	.240	.240	.240	1.680	1.680	1.650
45.0 - 46.0	20.6	38.8	40.7	.240	.240	.240	1.680	1.680	1.672

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: ECAR
SUB-REGION: CCD
UTILITY: CG&E

SHEET 5 OF 7

CONTRACT NO. DACW72 78 C 0013
DATE MARCH 1980

EXHIBIT II-3

ECAR MECS DETROIT EDISON COMPANY

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 56.2
SUMMER 63.4
WINTER 64.5

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	71.6	81.3	80.4	.024	.023	.010	.038	.025	.037
1.0 - 2.0	70.6	80.3	79.4	.034	.049	.016	.140	.084	.060
2.0 - 3.0	69.6	79.3	78.4	.065	.063	.033	.274	.135	.093
3.0 - 4.0	68.6	78.3	77.4	.115	.080	.040	.377	.183	.157
4.0 - 5.0	67.6	77.3	76.4	.120	.086	.040	.466	.238	.242
5.0 - 6.0	66.6	76.3	75.4	.120	.093	.052	.500	.306	.355
6.0 - 7.0	65.6	75.3	74.4	.134	.115	.065	.548	.356	.414
7.0 - 8.0	64.6	74.3	73.4	.140	.120	.117	.572	.409	.530
8.0 - 9.0	63.6	73.3	72.4	.140	.127	.140	.595	.427	.615
9.0 - 10.0	62.6	72.3	71.4	.150	.140	.145	.620	.450	.672
10.0 - 11.0	61.6	71.3	70.4	.154	.141	.152	.624	.493	.700
11.0 - 12.0	60.6	70.3	69.4	.160	.150	.160	.642	.540	.724
12.0 - 13.0	59.6	69.3	68.4	.160	.150	.160	.660	.603	.756
13.0 - 14.0	58.6	68.3	67.4	.160	.150	.160	.660	.651	.765
14.0 - 15.0	57.6	67.3	66.4	.165	.150	.160	.665	.667	.801
15.0 - 16.0	56.6	66.3	65.4	.170	.150	.160	.679	.683	.818
16.0 - 17.0	55.6	65.3	64.4	.170	.160	.165	.696	.720	.829
17.0 - 18.0	54.6	64.3	63.4	.170	.169	.170	.733	.752	.853
18.0 - 19.0	53.6	63.3	62.4	.170	.170	.170	.767	.781	.878
19.0 - 20.0	52.6	62.3	61.4	.177	.170	.180	.797	.835	.933
20.0 - 21.0	51.6	61.3	60.4	.180	.170	.180	.846	.904	1.014
21.0 - 22.0	50.6	60.3	59.4	.180	.170	.180	.921	.937	1.050
22.0 - 23.0	49.6	59.3	58.4	.180	.170	.180	1.032	1.002	1.083
23.0 - 24.0	48.6	58.3	57.4	.180	.170	.188	1.118	1.047	1.108
24.0 - 25.0	47.6	57.3	56.4	.180	.170	.190	1.168	1.093	1.120
25.0 - 26.0	46.6	56.3	55.4	.182	.180	.198	1.274	1.161	1.162
26.0 - 27.0	45.6	55.3	54.4	.192	.180	.200	1.363	1.170	1.195
27.0 - 28.0	44.6	54.3	53.4	.204	.180	.212	1.430	1.196	1.229
28.0 - 29.0	43.6	53.3	52.4	.215	.188	.228	1.477	1.225	1.295
29.0 - 30.0	42.6	52.3	51.4	.229	.190	.240	1.517	1.250	1.390
30.0 - 31.0	41.6	51.3	50.4	.239	.200	.240	1.556	1.315	1.439
31.0 - 32.0	40.6	50.3	49.4	.240	.210	.240	1.580	1.376	1.505
32.0 - 33.0	39.6	49.3	48.4	.240	.230	.240	1.606	1.451	1.536
33.0 - 34.0	38.6	48.3	47.4	.240	.240	.240	1.652	1.492	1.565
34.0 - 35.0	37.6	47.3	46.4	.240	.240	.240	1.677	1.527	1.603
35.0 - 36.0	36.6	46.3	45.4	.240	.240	.240	1.680	1.551	1.612
36.0 - 37.0	35.6	45.3	44.4	.240	.240	.240	1.680	1.595	1.625
37.0 - 38.0	34.6	44.3	43.4	.240	.240	.240	1.680	1.610	1.654
38.0 - 39.0	33.6	43.3	42.4	.240	.240	.240	1.680	1.655	1.680
39.0 - 40.0	32.6	42.3	41.4	.240	.240	.240	1.680	1.679	1.680
40.0 - 41.0	31.6	41.3	40.4	.240	.240	.240	1.680	1.680	1.680
41.0 - 42.0	30.6	40.3	39.4	.240	.240	.240	1.680	1.680	1.680

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: ECAR
SUB-REGION: MECS
UTILITY: DE

SHEET 6 OF 7

CONTRACT NO. DACW72 78 C 0013
DATE: MARCH 1980

EXHIBIT II-3

ECAR KY-IND PUBLIC SERVICE COMPANY OF INDIANA, INC.

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 58.5 / SUMMER 62.8 / WINTER 76.5

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	76.9	84.4	97.1	.022	.018	.011	.025	.018	.011
1.0 - 2.0	75.9	83.4	96.1	.049	.020	.020	.066	.020	.020
2.0 - 3.0	74.9	82.4	95.1	.074	.024	.020	.114	.031	.026
3.0 - 4.0	73.9	81.4	94.1	.098	.034	.028	.144	.084	.040
4.0 - 5.0	72.9	80.4	93.1	.124	.043	.036	.184	.128	.063
5.0 - 6.0	71.9	79.4	92.1	.140	.050	.040	.210	.183	.080
6.0 - 7.0	70.9	78.4	91.1	.140	.050	.040	.256	.233	.098
7.0 - 8.0	69.9	77.4	90.1	.149	.050	.041	.310	.280	.141
8.0 - 9.0	68.9	76.4	89.1	.151	.050	.074	.354	.308	.228
9.0 - 10.0	67.9	75.4	88.1	.160	.058	.088	.399	.348	.269
10.0 - 11.0	66.9	74.4	87.1	.160	.068	.114	.446	.390	.334
11.0 - 12.0	65.9	73.4	86.1	.160	.070	.124	.481	.419	.397
12.0 - 13.0	64.9	72.4	85.1	.160	.080	.130	.512	.445	.442
13.0 - 14.0	63.9	71.4	84.1	.160	.090	.139	.531	.478	.516
14.0 - 15.0	62.9	70.4	83.1	.160	.090	.142	.551	.499	.605
15.0 - 16.0	61.9	69.4	82.1	.167	.107	.150	.579	.545	.673
16.0 - 17.0	60.9	68.4	81.1	.178	.118	.150	.613	.610	.736
17.0 - 18.0	59.9	67.4	80.1	.180	.126	.150	.641	.641	.780
18.0 - 19.0	58.9	66.4	79.1	.180	.130	.153	.695	.684	.823
19.0 - 20.0	57.9	65.4	78.1	.180	.136	.160	.743	.725	.888
20.0 - 21.0	56.9	64.4	77.1	.180	.140	.170	.801	.751	.927
21.0 - 22.0	55.9	63.4	76.1	.180	.140	.170	.833	.799	.949
22.0 - 23.0	54.9	62.4	75.1	.180	.146	.170	.904	.837	.958
23.0 - 24.0	53.9	61.4	74.1	.187	.150	.170	1.001	.896	.983
24.0 - 25.0	52.9	60.4	73.1	.190	.150	.170	1.051	.936	1.023
25.0 - 26.0	51.9	59.4	72.1	.194	.158	.170	1.121	.964	1.046
26.0 - 27.0	50.9	58.4	71.1	.204	.160	.170	1.209	.996	1.080
27.0 - 28.0	49.9	57.4	70.1	.222	.164	.170	1.277	1.018	1.106
28.0 - 29.0	48.9	56.4	69.1	.240	.170	.170	1.355	1.059	1.146
29.0 - 30.0	47.9	55.4	68.1	.240	.170	.178	1.381	1.090	1.210
30.0 - 31.0	46.9	54.4	67.1	.240	.170	.180	1.429	1.121	1.242
31.0 - 32.0	45.9	53.4	66.1	.240	.177	.180	1.464	1.153	1.263
32.0 - 33.0	44.9	52.4	65.1	.240	.189	.180	1.489	1.205	1.273
33.0 - 34.0	43.9	51.4	64.1	.240	.199	.180	1.533	1.259	1.334
34.0 - 35.0	42.9	50.4	63.1	.240	.200	.180	1.570	1.266	1.374
35.0 - 36.0	41.9	49.4	62.1	.240	.216	.180	1.595	1.321	1.396
36.0 - 37.0	40.9	48.4	61.1	.240	.235	.180	1.639	1.392	1.433
37.0 - 38.0	39.9	47.4	60.1	.240	.240	.189	1.657	1.462	1.477
38.0 - 39.0	38.9	46.4	59.1	.240	.240	.194	1.677	1.520	1.499
39.0 - 40.0	37.9	45.4	58.1	.240	.240	.200	1.680	1.537	1.511
40.0 - 41.0	36.9	44.4	57.1	.240	.240	.207	1.680	1.562	1.527
41.0 - 42.0	35.9	43.4	56.1	.240	.240	.227	1.680	1.591	1.554
42.0 - 43.0	34.9	42.4	55.1	.240	.240	.240	1.680	1.609	1.589
43.0 - 44.0	33.9	41.4	54.1	.240	.240	.240	1.680	1.659	1.625
44.0 - 45.0	32.9	40.4	53.1	.240	.240	.240	1.680	1.680	1.635
45.0 - 46.0	31.9	39.4	52.1	.240	.240	.240	1.680	1.680	1.657

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: ECAR
SUB-REGION: KY-IND
UTILITY: PSI

SHEET 7 OF 7

CONTRACT NO. DACW72-78-C-0013
DATE: MARCH 1980

EXHIBIT II-3

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
MID ATLANTIC AREA COUNCIL

SERVICE AREA APPROXIMATED BY BEA AREAS:
10 11 13 14 1/ 15 16 17

SECTOR EARNINGS (MILLION $)	YEAR 1980	1985	1990	2000
AGRICULTURE	714.	738.	764.	852.
MINING	166.	172.	179.	203.
CONSTRUCTION	5286.	6146.	7147.	9702.
MANUFACTURING	24270.	27463.	31084.	40502.
TRANSPO UTILITIES	6417.	7451.	8651.	11836.
TRADE	13870.	15867.	18153.	24324.
FINANCE	5870.	7031.	8423.	12140.
SERVICES	16962.	21066.	26163.	39829.
GOVERNMENT	13845.	16739.	20238.	29322.
TOTAL EARNINGS (MILLION $)	87402.	102754.	120806.	168713.
TOTAL PERSONAL INCOME (MILLION $)	112330.	132431.	156137.	218745.
TOTAL POPULATION (THOUSANDS)	21419.	22336.	23294.	24865.
PER CAPITA INCOME ($)	5245.	5929.	6703.	8797.
PER CAPTA INCOME RELATIVE TO U. S.	1.10	1.09	1.09	1.08

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

1/ Only a portion of BEA 14 (35%) is included in the MAAC regional analysis.

HARZA ENGINEERING COMPANY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: MAAC

SUB-REGION: MAAC

SHEET 1 OF 1

CONTRACT NO DACW72 - 78 - C - 0013

DATE MARCH 1980

EXHIBIT III-1

ELECTRIC POWER DEMAND
MID ATLANTIC AREA COUNCIL(MAAC)
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	20007.	.4	20574.	.8	21410.	.7	22170.	.7	22957.	.6
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	8.5	3.2	10.6	2.1	11.7	1.6	12.7	1.7	13.8	2.2
TOTAL DEMAND(THOUSAND GWH)	169.8	3.6	217.8	2.9	251.1	2.3	282.0	2.4	317.2	2.9
PEAK DEMAND(GW)	31.8	3.5	40.4	2.8	46.3	2.3	52.0	2.4	58.5	2.8
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	8.5	2.6	10.2	2.6	11.5	2.6	13.1	2.6	14.9	2.6
TOTAL DEMAND(THOUSAND GWH)	169.8	3.0	209.0	3.4	247.3	3.3	291.1	3.3	342.7	3.2
PEAK DEMAND(GW)	31.8	2.9	38.8	3.3	45.6	3.3	53.7	3.3	63.2	3.2
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	8.5	4.5	11.5	4.0	14.1	3.3	16.5	3.2	19.3	3.8
TOTAL DEMAND(THOUSAND GWH)	169.8	4.9	237.6	4.8	300.9	4.0	366.4	3.9	444.2	4.5
PEAK DEMAND(GW)	31.8	4.8	44.1	4.7	55.5	4.0	67.6	3.9	81.9	4.4
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	8.5	3.2	10.6	2.1	11.7	2.3	13.1	2.6	14.9	2.6
TOTAL DEMAND(THOUSAND GWH)	169.8	3.6	217.8	2.9	251.1	3.0	291.1	3.3	342.7	3.2
PEAK DEMAND(GW)	31.8	3.5	40.4	2.8	46.3	3.0	53.7	3.3	63.2	3.2
MARGIN(PERCENT)			25.0		25.0		25.0		25.0	
RESOURCES TO SERVE DEMAND(GW)			50.5		57.9		67.1		79.0	
LOAD FACTOR(PERCENT)	61.0		61.5		61.9		61.9		61.9	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: MAAC
SUB-REGION: MAAC

SHEET 1 OF 1

CONTRACT NO. DACW72 - 78 - C - 0013

DATE: MARCH 1980

EXHIBIT III-2

MAAC PJM INTERCONNECTION

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 53.3
SUMMER 69.8
WINTER 64.1

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO (PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	67.7	91.5	80.8	.030	.026	.011	.036	.035	.011
1.0 - 2.0	66.7	90.5	79.8	.082	.045	.020	.160	.079	.020
2.0 - 3.0	65.7	89.5	78.8	.110	.051	.025	.240	.101	.029
3.0 - 4.0	64.7	88.5	77.8	.120	.062	.037	.319	.140	.076
4.0 - 5.0	63.7	87.5	76.8	.120	.078	.059	.389	.204	.133
5.0 - 6.0	62.7	86.5	75.8	.127	.080	.083	.463	.246	.229
6.0 - 7.0	61.7	85.5	74.8	.138	.088	.110	.514	.318	.346
7.0 - 8.0	60.7	84.5	73.8	.140	.101	.131	.548	.368	.433
8.0 - 9.0	59.7	83.5	72.8	.140	.110	.140	.565	.434	.525
9.0 - 10.0	58.7	82.5	71.8	.140	.117	.140	.588	.475	.602
10.0 - 11.0	57.7	81.5	70.8	.140	.121	.145	.614	.483	.694
11.0 - 12.0	56.7	80.5	69.8	.142	.130	.150	.630	.528	.739
12.0 - 13.0	55.7	79.5	68.8	.156	.130	.151	.675	.578	.748
13.0 - 14.0	54.7	78.5	67.8	.160	.130	.160	.725	.591	.783
14.0 - 15.0	53.7	77.5	66.8	.160	.130	.160	.750	.608	.818
15.0 - 16.0	52.7	76.5	65.8	.160	.134	.160	.784	.629	.848
16.0 - 17.0	51.7	75.5	64.8	.160	.140	.160	.862	.651	.890
17.0 - 18.0	50.7	74.5	63.8	.166	.140	.160	.897	.671	.910
18.0 - 19.0	49.7	73.5	62.8	.170	.150	.161	.935	.698	.941
19.0 - 20.0	48.7	72.5	61.8	.170	.150	.177	.985	.720	.978
20.0 - 21.0	47.7	71.5	60.8	.170	.150	.180	1.027	.729	.990
21.0 - 22.0	46.7	70.5	59.8	.170	.150	.180	1.084	.743	.995
22.0 - 23.0	45.7	69.5	58.8	.175	.152	.180	1.142	.765	1.041
23.0 - 24.0	44.7	68.5	57.8	.180	.160	.180	1.217	.788	1.083
24.0 - 25.0	43.7	67.5	56.8	.180	.160	.180	1.256	.840	1.100
25.0 - 26.0	42.7	66.5	55.8	.180	.160	.180	1.336	.882	1.135
26.0 - 27.0	41.7	65.5	54.8	.180	.160	.187	1.427	.905	1.175
27.0 - 28.0	40.7	64.5	53.8	.180	.162	.200	1.517	.954	1.236
28.0 - 29.0	39.7	63.5	52.8	.183	.170	.201	1.543	1.055	1.290
29.0 - 30.0	38.7	62.5	51.8	.199	.170	.223	1.565	1.094	1.336
30.0 - 31.0	37.7	61.5	50.8	.207	.170	.240	1.581	1.124	1.383
31.0 - 32.0	36.7	60.5	49.8	.230	.170	.240	1.610	1.139	1.431
32.0 - 33.0	35.7	59.5	48.8	.240	.170	.240	1.629	1.151	1.480
33.0 - 34.0	34.7	58.5	47.8	.240	.170	.240	1.648	1.180	1.490
34.0 - 35.0	33.7	57.5	46.8	.240	.174	.240	1.668	1.195	1.510
35.0 - 36.0	32.7	56.5	45.8	.240	.180	.240	1.680	1.229	1.550
36.0 - 37.0	31.7	55.5	44.8	.240	.180	.240	1.680	1.281	1.572
37.0 - 38.0	30.7	54.5	43.8	.240	.189	.240	1.680	1.340	1.605
38.0 - 39.0	29.7	53.5	42.8	.240	.200	.240	1.680	1.376	1.632
39.0 - 40.0	28.7	52.5	41.8	.240	.201	.240	1.680	1.429	1.654
40.0 - 41.0	27.7	51.5	40.8	.240	.212	.240	1.680	1.487	1.679
41.0 - 42.0	26.7	50.5	39.8	.240	.232	.240	1.680	1.546	1.680
42.0 - 43.0	25.7	49.5	38.8	.240	.240	.240	1.680	1.583	1.680
43.0 - 44.0	24.7	48.5	37.8	.240	.240	.240	1.680	1.593	1.680
44.0 - 45.0	23.7	47.5	36.8	.240	.240	.240	1.680	1.609	1.680
45.0 - 46.0	22.7	46.5	35.8	.240	.240	.240	1.680	1.639	1.680

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: MAAC
SUB-REGION: MAAC
UTILITY: PJM

SHEET 1 OF 1

CONTRACT NO. DACW72-78-C-0013

DATE MARCH 1980

EXHIBIT III-3

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
MID AMERICA
INTERPOOL NETWORK(MAIN)

SERVICE AREA APPROXIMATED BY BEA AREAS:
57 58 77 78 79 82 83 84 85 86
112 113 114

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	1739.	1792.	1848.	2053.
MINING	355.	376.	397.	458.
CONSTRUCTION	5439.	6262.	7210.	9617.
MANUFACTURING	26558.	30194.	34340.	44941.
TRANSPO UTILITIES	5742.	6605.	7620.	10287.
TRADE	13418.	15293.	17433.	23239.
FINANCE	4503.	5424.	6535.	9462.
SERVICES	13822.	17056.	21050.	31703.
GOVERNMENT	11638.	14069.	17010.	24705.
TOTAL EARNINGS (MILLION $)	83219.	97157.	113450.	156470.
TOTAL PERSONAL INCOME (MILLION $)	104487.	122742.	144215.	200691.
TOTAL POPULATION (THOUSANDS)	20182.	20919.	21686.	22933.
PER CAPITA INCOME ($)	5177.	5867.	6650.	8751.
PER CAPTA INCOME RELATIVE TO U. S.	1.08	1.08	1.08	1.07

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: MAIN
SUB-REGION: MAIN

SHEET 1 OF 4

CONTRACT NO. DACW72-78-C-0013
DATE: MARCH 1980

EXHIBIT IV-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
MID AMERICA INTERPOOL NETWORK
COMMONWEALTH EDISON

SERVICE AREA APPROXIMATED BY BEA AREAS:
77 79 82

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	492.	504.	516.	569.
MINING	77.	79.	82.	92.
CONSTRUCTION	3147.	3617.	4157.	5533.
MANUFACTURING	15249.	17302.	19632.	25652.
TRANSPO UTILITIES	3343.	3846.	4424.	5953.
TRADE	7764.	8860.	10111.	13519.
FINANCE	2697.	3241.	3894.	5636.
SERVICES	8134.	10029.	12365.	18597.
GOVERNMENT	5789.	7020.	8512.	12443.
TOTAL EARNINGS (MILLION $)	46695.	54536.	63695.	87995.
TOTAL PERSONAL INCOME (MILLION $)	57586.	67738.	79682.	111215.
TOTAL POPULATION (THOUSANDS)	10258.	10683.	11127.	11892.
PER CAPITA INCOME ($)	5614.	6341.	7161.	9352.
PER CAPTA INCOME RELATIVE TO U. S.	1.17	1.17	1.16	1.15

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: MAIN
SUB-REGION: CECO

SHEET 2 OF 4

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980
EXHIBIT IV-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
MID AMERICA INTERPOOL NETWORK
ILLINOIS-MISSOURI

SERVICE AREA APPROXIMATED BY BEA AREAS:
57 58 78 112 113 114

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	837.	866.	897.	1001.
MINING	223.	240.	258.	304.
CONSTRUCTION	1383.	1597.	1845.	2462.
MANUFACTURING	6162.	7089.	8162.	10807.
TRANSPO UTILITIES	1523.	1750.	2011.	2712.
TRADE	3362.	3832.	4370.	5800.
FINANCE	1066.	1291.	1564.	2264.
SERVICES	3366.	4168.	5161.	7790.
GOVERNMENT	3568.	4293.	5167.	7421.
TOTAL EARNINGS (MILLION $)	21492.	25151.	29438.	40564.
TOTAL PERSONAL INCOME (MILLION $)	27708.	32580.	38317.	53173.
TOTAL POPULATION (THOUSANDS)	5860.	6049.	6245.	6524.
PER CAPITA INCOME ($)	4728.	5386.	6135.	8150.
PER CAPTA INCOME RELATIVE TO U. S.	.99	.99	1.00	1.00

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: MAIN

SUB-REGION: ILL-MO.

SHEET 3 OF 4

CONTRACT NO. DACW72-78-C-0013

DATE MARCH 1980

EXHIBIT IV-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
MID AMERICA INTERPOOL NETWORK
WISCONSIN-UPPER MICHIGAN SYSTEM

SERVICE AREA APPROXIMATED BY BEA AREAS:
83 84 85 86

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	409.	422.	435.	483.
MINING	55.	56.	57.	62.
CONSTRUCTION	909.	1048.	1208.	1621.
MANUFACTURING	5147.	5803.	6546.	8482.
TRANSPO UTILITIES	876.	1010.	1185.	1623.
TRADE	2292.	2600.	2952.	3919.
FINANCE	740.	892.	1077.	1562.
SERVICES	2322.	2859.	3524.	5316.
GOVERNMENT	2281.	2756.	3331.	4841.
TOTAL EARNINGS (MILLION $)	15032.	17470.	20317.	27911.
TOTAL PERSONAL INCOME (MILLION $)	19193.	22424.	26216.	36304.
TOTAL POPULATION (THOUSANDS)	4065.	4187.	4314.	4517.
PER CAPITA INCOME ($)	4722.	5356.	6076.	8036.
PER CAPTA INCOME RELATIVE TO U. S.	.99	.99	.99	.98

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS
REGION: MAIN
SUB-REGION: WUMS

SHEET 4 OF 4

CONTRACT NO DACW72-78-C-0013
DATE MARCH 1980
EXHIBIT IV-1

ELECTRIC POWER DEMAND
MID AMERICA INTERPOOL NETWORK REGION(MAIN)
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	19122.	.5	19819.	.7	20523.	.6	21115.	.6	21726.	.6
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	8.8	4.2	11.7	3.7	14.1	3.7	16.9	3.8	20.3	3.9
TOTAL DEMAND(THOUSAND GWH)	168.8	4.7	232.8	4.4	289.4	4.3	356.8	4.4	441.6	4.5
PEAK DEMAND(GW)	33.2	5.1	46.9	4.3	58.0	4.3	71.6	4.4	88.7	4.6
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	8.8	2.6	10.6	2.6	12.0	2.6	13.6	2.6	15.5	2.6
TOTAL DEMAND(THOUSAND GWH)	168.8	3.1	209.3	3.3	246.2	3.2	287.6	3.2	335.9	3.2
PEAK DEMAND(GW)	33.2	3.5	42.2	3.2	49.3	3.2	57.7	3.2	67.5	3.3
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	8.8	4.5	12.0	4.0	14.6	3.3	17.1	3.2	20.0	3.8
TOTAL DEMAND(THOUSAND GWH)	168.8	5.0	238.0	4.7	299.5	3.9	362.0	3.8	435.4	4.4
PEAK DEMAND(GW)	33.2	5.4	47.9	4.6	60.0	3.9	72.6	3.8	87.5	4.5
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	8.8	4.1	11.7	3.6	14.0	3.3	16.5	3.3	19.4	3.6
TOTAL DEMAND(THOUSAND GWH)	168.8	4.7	232.5	4.3	287.5	3.9	347.9	3.9	421.4	4.2
PEAK DEMAND(GW)	33.2	5.0	46.8	4.2	57.6	3.9	69.8	3.9	84.7	4.3
MARGIN(PERCENT)			20.7		18.2		18.1		18.1	
RESOURCES TO SERVE DEMAND(GW)			56.5		68.1		82.5		100.0	
LOAD FACTOR(PERCENT)	58.0		56.7		57.0		56.9		56.8	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: MAIN
SUB-REGION: MAIN

SHEET 1 OF 4

CONTRACT NO. DACW72-78-C-0013
DATE MARCH 1980

EXHIBIT IV-2

ELECTRIC POWER DEMAND
COMMONWEALTH EDISON SUB-REGION
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	9493.	.5	9830.	.8	10230.	.7	10593.	.7	10969.	.7
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	7.2	4.1	9.5	3.6	11.3	3.6	13.5	3.6	16.1	3.8
TOTAL DEMAND(THOUSAND GWH)	67.9	4.7	93.4	4.4	115.8	4.3	143.0	4.3	176.8	4.4
PEAK DEMAND(GW)	13.7	5.3	19.7	4.3	24.3	4.3	30.0	4.3	37.1	4.6
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	7.2	2.6	8.6	2.6	9.7	2.6	11.1	2.6	12.6	2.6
TOTAL DEMAND(THOUSAND GWH)	67.9	3.1	84.1	3.4	99.6	3.3	117.2	3.3	138.0	3.3
PEAK DEMAND(GW)	13.7	3.8	17.7	3.3	20.9	3.3	24.6	3.3	29.0	3.5
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	7.2	4.5	9.7	4.0	11.8	3.3	13.9	3.2	16.3	3.8
TOTAL DEMAND(THOUSAND GWH)	67.9	5.0	95.7	4.8	121.1	4.0	147.6	3.9	178.9	4.5
PEAK DEMAND(GW)	13.7	5.7	20.2	4.7	25.4	4.0	31.0	3.9	37.5	4.7
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	7.2	4.1	9.5	3.6	11.3	3.6	13.5	3.6	16.1	3.8
TOTAL DEMAND(THOUSAND GWH)	67.9	4.7	93.4	4.4	115.8	4.3	143.0	4.3	176.8	4.4
PEAK DEMAND(GW)	13.7	5.3	19.7	4.3	24.3	4.3	30.0	4.3	37.1	4.6
MARGIN(PERCENT)			23.0		17.0		17.0		17.0	
RESOURCES TO SERVE DEMAND(GW)			24.2		28.4		35.1		43.4	
LOAD FACTOR(PERCENT)	56.6		54.1		54.4		54.4		54.4	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: MAIN
SUB-REGION: CECO

SHEET 2 OF 4

CONTRACT NO. DACW72-78-C-0013
DATE MARCH 1980

EXHIBIT IV-2

ELECTRIC POWER DEMAND
ILLINOIS-MISSOURI SUB-REGION
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	5593.	.4	5751.	.6	5926.	.4	6045.	.4	6167.	.4
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	11.4	4.6	15.6	4.3	19.2	4.3	23.7	4.3	29.3	4.4
TOTAL DEMAND(THOUSAND GWH)	63.8	5.0	89.6	4.9	113.8	4.7	143.2	4.7	180.5	4.8
PEAK DEMAND(GW)	13.0	5.1	18.4	4.7	23.2	4.7	29.2	4.7	36.8	4.8
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	11.4	2.6	13.7	2.6	15.5	2.6	17.6	2.6	20.1	2.6
TOTAL DEMAND(THOUSAND GWH)	63.8	3.0	78.5	3.2	92.0	3.0	106.7	3.0	123.7	3.1
PEAK DEMAND(GW)	13.0	3.1	16.1	3.1	18.8	3.0	21.7	3.0	25.2	3.1
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	11.4	4.5	15.5	4.0	18.9	3.3	22.2	3.2	26.0	3.8
TOTAL DEMAND(THOUSAND GWH)	63.8	4.9	89.3	4.6	111.9	3.7	134.3	3.6	160.4	4.3
PEAK DEMAND(GW)	13.0	5.0	18.3	4.5	22.8	3.7	27.4	3.6	32.7	4.3
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	11.4	4.5	15.5	4.0	18.9	3.3	22.2	3.2	26.0	3.8
TOTAL DEMAND(THOUSAND GWH)	63.8	4.9	89.3	4.6	111.9	3.7	134.3	3.6	160.4	4.3
PEAK DEMAND(GW)	13.0	5.0	18.3	4.5	22.8	3.7	27.4	3.6	32.7	4.3
MARGIN(PERCENT)			20.0		20.0		20.0		20.0	
RESOURCES TO SERVE DEMAND(GW)			22.0		27.4		32.9		39.2	
LOAD FACTOR(PERCENT)	56.0		55.6		56.0		56.0		56.0	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

ELECTRIC POWER DEMAND
WISCONSIN-UPPER MICHIGAN SUB-REGION
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	4036.	.7	4238.	.6	4367.	.5	4477.	.5	4590.	.6
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	9.2	3.6	11.8	3.1	13.7	2.9	15.8	3.1	18.4	3.2
TOTAL DEMAND(THOUSAND GWH)	37.1	4.3	49.8	3.7	59.8	3.4	70.6	3.6	84.3	3.8
PEAK DEMAND(GW)	6.5	4.4	8.8	3.6	10.5	3.4	12.4	3.6	14.8	3.8
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	9.2	2.6	11.0	2.6	12.5	2.6	14.2	2.6	16.2	2.6
TOTAL DEMAND(THOUSAND GWH)	37.1	3.3	46.6	3.2	54.6	3.1	63.7	3.1	74.2	3.2
PEAK DEMAND(GW)	6.5	3.4	8.2	3.1	9.6	3.1	11.2	3.1	13.0	3.2
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	9.2	4.5	12.5	4.0	15.2	3.3	17.9	3.2	21.0	3.8
TOTAL DEMAND(THOUSAND GWH)	37.1	5.2	53.0	4.6	66.5	3.8	80.1	3.7	96.2	4.4
PEAK DEMAND(GW)	6.5	5.4	9.4	4.5	11.7	3.8	14.1	3.7	16.9	4.4
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	9.2	3.6	11.8	3.1	13.7	2.9	15.8	3.1	18.4	3.2
TOTAL DEMAND(THOUSAND GWH)	37.1	4.3	49.8	3.7	59.8	3.4	70.6	3.6	84.3	3.8
PEAK DEMAND(GW)	6.5	4.4	8.8	3.6	10.5	3.4	12.4	3.6	14.8	3.8
MARGIN(PERCENT)			17.0		17.0		17.0		17.0	
RESOURCES TO SERVE DEMAND(GW)			10.3		12.3		14.5		17.3	
LOAD FACTOR(PERCENT)	65.2		64.6		65.0		65.0		65.0	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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CHICAGO, ILLINOIS

DEPARTMENT OF THE ARMY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: MAIN
SUB-REGION: WUMS

SHEET 4 OF 4

CONTRACT NO. DACW72 - 78 - C - 0013
DATE MARCH 1980

EXHIBIT IV-2

MAIN CECO COMMONWEALTH EDISON COMPANY

YEAR: 1985
WEEKLY LOAD FACTOR: OFF-SEASON 48.2
SUMMER 56.8
WINTER 59.9

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	63.9	83.3	74.7	.014	.018	.010	.014	.018	.020
1.0 - 2.0	62.9	82.3	73.7	.040	.037	.016	.040	.037	.038
2.0 - 3.0	61.9	81.3	72.7	.064	.040	.047	.084	.040	.084
3.0 - 4.0	60.9	80.3	71.7	.093	.051	.092	.194	.051	.153
4.0 - 5.0	59.9	79.3	70.7	.113	.060	.107	.271	.060	.207
5.0 - 6.0	58.9	78.3	69.7	.130	.067	.129	.385	.067	.333
6.0 - 7.0	57.9	77.3	68.7	.136	.080	.130	.445	.080	.423
7.0 - 8.0	56.9	76.3	67.7	.140	.083	.131	.483	.083	.522
8.0 - 9.0	55.9	75.3	66.7	.140	.109	.140	.526	.109	.592
9.0 - 10.0	54.9	74.3	65.7	.149	.110	.146	.546	.110	.666
10.0 - 11.0	53.9	73.3	64.7	.150	.116	.150	.581	.116	.704
11.0 - 12.0	52.9	72.3	63.7	.158	.120	.151	.600	.120	.729
12.0 - 13.0	51.9	71.3	62.7	.160	.125	.160	.622	.133	.768
13.0 - 14.0	50.9	70.3	61.7	.160	.130	.160	.631	.194	.793
14.0 - 15.0	49.9	69.3	60.7	.160	.130	.160	.653	.265	.828
15.0 - 16.0	48.9	68.3	59.7	.160	.134	.166	.687	.284	.874
16.0 - 17.0	47.9	67.3	58.7	.170	.140	.175	.724	.328	.904
17.0 - 18.0	46.9	66.3	57.7	.175	.140	.180	.762	.348	.947
18.0 - 19.0	45.9	65.3	56.7	.180	.142	.180	.818	.392	.980
19.0 - 20.0	44.9	64.3	55.7	.180	.150	.180	.866	.454	1.011
20.0 - 21.0	43.9	63.3	54.7	.180	.150	.180	.906	.522	1.040
21.0 - 22.0	42.9	62.3	53.7	.189	.150	.188	.981	.552	1.074
22.0 - 23.0	41.9	61.3	52.7	.195	.155	.190	1.049	.603	1.122
23.0 - 24.0	40.9	60.3	51.7	.204	.160	.200	1.128	.650	1.185
24.0 - 25.0	39.9	59.3	50.7	.228	.160	.207	1.212	.667	1.246
25.0 - 26.0	38.9	58.3	49.7	.240	.160	.234	1.292	.697	1.320
26.0 - 27.0	37.9	57.3	48.7	.240	.169	.240	1.384	.757	1.371
27.0 - 28.0	36.9	56.3	47.7	.240	.170	.240	1.477	.802	1.407
28.0 - 29.0	35.9	55.3	46.7	.240	.170	.240	1.519	.882	1.436
29.0 - 30.0	34.9	54.3	45.7	.240	.170	.240	1.582	.973	1.507
30.0 - 31.0	33.9	53.3	44.7	.240	.170	.240	1.624	1.005	1.543
31.0 - 32.0	32.9	52.3	43.7	.240	.170	.240	1.658	1.045	1.558
32.0 - 33.0	31.9	51.3	42.7	.240	.170	.240	1.678	1.074	1.571
33.0 - 34.0	30.9	50.3	41.7	.240	.173	.240	1.680	1.100	1.604
34.0 - 35.0	29.9	49.3	40.7	.240	.180	.240	1.680	1.142	1.656
35.0 - 36.0	28.9	48.3	39.7	.240	.188	.240	1.680	1.187	1.680
36.0 - 37.0	27.9	47.3	38.7	.240	.195	.240	1.680	1.227	1.680
37.0 - 38.0	26.9	46.3	37.7	.240	.200	.240	1.680	1.266	1.680
38.0 - 39.0	25.9	45.3	36.7	.240	.203	.240	1.680	1.317	1.680
39.0 - 40.0	24.9	44.3	35.7	.240	.223	.240	1.680	1.377	1.680
40.0 - 41.0	23.9	43.3	34.7	.240	.235	.240	1.680	1.415	1.680
41.0 - 42.0	22.9	42.3	33.7	.240	.240	.240	1.680	1.462	1.680
42.0 - 43.0	21.9	41.3	32.7	.240	.240	.240	1.680	1.488	1.680
43.0 - 44.0	20.9	40.3	31.7	.240	.240	.240	1.680	1.503	1.680
44.0 - 45.0	19.9	39.3	30.7	.240	.240	.240	1.680	1.532	1.680
45.0 - 46.0	18.9	38.3	29.7	.240	.240	.240	1.680	1.558	1.680

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SEASONAL ENERGY REQUIREMENTS

REGION: MAIN
SUB-REGION: CECO
UTILITY: CECO

SHEET 1 OF 3

CONTRACT NO. DACW72-78-C-0013
DATE MARCH 1980

EXHIBIT IV-3

MAIN WUMS WISCONSIN ELECTRIC - WISCONSIN MICHIGAN SYSTEM

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 53.9
SUMMER 61.5
WINTER 64.7

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO (PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	76.5	83.8	85.6	.018	.013	.010	.018	.018	.010
1.0 - 2.0	75.5	82.8	84.6	.024	.027	.015	.024	.071	.015
2.0 - 3.0	74.5	81.8	83.6	.040	.062	.020	.040	.130	.034
3.0 - 4.0	73.5	80.8	82.6	.064	.070	.036	.067	.152	.063
4.0 - 5.0	72.5	79.8	81.6	.079	.077	.040	.103	.198	.090
5.0 - 6.0	71.5	78.8	80.6	.093	.080	.041	.159	.232	.133
6.0 - 7.0	70.5	77.8	79.6	.122	.088	.063	.227	.275	.211
7.0 - 8.0	69.5	76.8	78.6	.130	.096	.085	.299	.296	.298
8.0 - 9.0	68.5	75.8	77.6	.130	.110	.104	.370	.328	.390
9.0 - 10.0	67.5	74.8	76.6	.130	.119	.130	.421	.363	.483
10.0 - 11.0	66.5	73.8	75.6	.130	.125	.134	.437	.423	.565
11.0 - 12.0	65.5	72.8	74.6	.133	.139	.140	.478	.486	.625
12.0 - 13.0	64.5	71.8	73.6	.149	.140	.145	.530	.532	.660
13.0 - 14.0	63.5	70.8	72.6	.150	.140	.150	.569	.552	.677
14.0 - 15.0	62.5	69.8	71.6	.150	.140	.150	.587	.591	.701
15.0 - 16.0	61.5	68.8	70.6	.150	.140	.150	.600	.601	.725
16.0 - 17.0	60.5	67.8	69.6	.150	.140	.150	.600	.630	.753
17.0 - 18.0	59.5	66.8	68.6	.150	.148	.150	.600	.664	.767
18.0 - 19.0	58.5	65.8	67.6	.153	.152	.159	.621	.710	.779
19.0 - 20.0	57.5	64.8	66.6	.160	.160	.160	.643	.747	.782
20.0 - 21.0	56.5	63.8	65.6	.160	.160	.160	.670	.760	.817
21.0 - 22.0	55.5	62.8	64.6	.160	.160	.160	.696	.766	.820
22.0 - 23.0	54.5	61.8	63.6	.160	.160	.160	.708	.770	.851
23.0 - 24.0	53.5	60.8	62.6	.160	.160	.160	.720	.778	.887
24.0 - 25.0	52.5	59.8	61.6	.160	.160	.161	.761	.803	.913
25.0 - 26.0	51.5	58.8	60.6	.160	.164	.170	.803	.835	.947
26.0 - 27.0	50.5	57.8	59.6	.167	.170	.179	.856	.884	1.007
27.0 - 28.0	49.5	56.8	58.6	.178	.170	.180	.895	.934	1.025
28.0 - 29.0	48.5	55.8	57.6	.180	.170	.180	.938	.985	1.044
29.0 - 30.0	47.5	54.8	56.6	.180	.170	.180	.990	1.008	1.064
30.0 - 31.0	46.5	53.8	55.6	.180	.171	.180	1.006	1.061	1.084
31.0 - 32.0	45.5	52.8	54.6	.180	.180	.180	1.033	1.120	1.106
32.0 - 33.0	44.5	51.8	53.6	.180	.185	.180	1.089	1.161	1.137
33.0 - 34.0	43.5	50.8	52.6	.180	.190	.180	1.149	1.190	1.172
34.0 - 35.0	42.5	49.8	51.6	.180	.190	.180	1.211	1.211	1.214
35.0 - 36.0	41.5	48.8	50.6	.180	.190	.187	1.295	1.233	1.274
36.0 - 37.0	40.5	47.8	49.6	.185	.199	.192	1.376	1.264	1.343
37.0 - 38.0	39.5	46.8	48.6	.190	.210	.200	1.427	1.307	1.402
38.0 - 39.0	38.5	45.8	47.6	.190	.216	.200	1.451	1.360	1.462
39.0 - 40.0	37.5	44.8	46.6	.198	.238	.212	1.497	1.439	1.505
40.0 - 41.0	36.5	43.8	45.6	.209	.240	.233	1.531	1.463	1.544
41.0 - 42.0	35.5	42.8	44.6	.232	.240	.240	1.580	1.503	1.560
42.0 - 43.0	34.5	41.8	43.6	.240	.240	.240	1.618	1.545	1.569
43.0 - 44.0	33.5	40.8	42.6	.240	.240	.240	1.643	1.562	1.591
44.0 - 45.0	32.5	39.8	41.6	.240	.240	.240	1.673	1.598	1.617
45.0 - 46.0	31.5	38.8	40.6	.240	.240	.240	1.680	1.632	1.657

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SEASONAL ENERGY REQUIREMENTS

REGION: MAIN
SUB-REGION: WUMS
UTILITY: WUMS

CONTRACT NO. DACW72-78-C-0013

DATE: MARCH 1980

EXHIBIT IV-3

MAIN ILL-MO UNION ELECTRIC SYSTEM

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 43.3
SUMMER 60.4
WINTER 55.2

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	54.7	85.2	67.3	.036	.010	.024	.036	.010	.032
1.0 - 2.0	53.7	84.2	66.3	.082	.013	.030	.091	.013	.063
2.0 - 3.0	52.7	83.2	65.3	.113	.028	.040	.145	.028	.088
3.0 - 4.0	51.7	82.2	64.3	.136	.030	.053	.206	.030	.123
4.0 - 5.0	50.7	81.2	63.3	.142	.030	.097	.282	.030	.209
5.0 - 6.0	49.7	80.2	62.3	.150	.030	.121	.388	.030	.336
6.0 - 7.0	48.7	79.2	61.3	.150	.043	.140	.487	.057	.522
7.0 - 8.0	47.7	78.2	60.3	.159	.050	.141	.538	.084	.579
8.0 - 9.0	46.7	77.2	59.3	.160	.054	.150	.588	.116	.645
9.0 - 10.0	45.7	76.2	58.3	.160	.060	.156	.611	.154	.723
10.0 - 11.0	44.7	75.2	57.3	.162	.060	.161	.645	.188	.763
11.0 - 12.0	43.7	74.2	56.3	.174	.060	.170	.684	.221	.811
12.0 - 13.0	42.7	73.2	55.3	.180	.077	.170	.762	.264	.841
13.0 - 14.0	41.7	72.2	54.3	.180	.080	.174	.848	.288	.869
14.0 - 15.0	40.7	71.2	53.3	.183	.086	.180	.918	.326	.924
15.0 - 16.0	39.7	70.2	52.3	.199	.090	.180	1.014	.350	.964
16.0 - 17.0	38.7	69.2	51.3	.212	.091	.187	1.155	.381	1.036
17.0 - 18.0	37.7	68.2	50.3	.235	.100	.190	1.229	.417	1.105
18.0 - 19.0	36.7	67.2	49.3	.240	.107	.215	1.294	.435	1.178
19.0 - 20.0	35.7	66.2	48.3	.240	.127	.240	1.361	.485	1.279
20.0 - 21.0	34.7	65.2	47.3	.240	.140	.240	1.421	.567	1.378
21.0 - 22.0	33.7	64.2	46.3	.240	.140	.240	1.474	.623	1.451
22.0 - 23.0	32.7	63.2	45.3	.240	.140	.240	1.547	.681	1.500
23.0 - 24.0	31.7	62.2	44.3	.240	.141	.240	1.651	.743	1.512
24.0 - 25.0	30.7	61.2	43.3	.240	.150	.240	1.680	.808	1.525
25.0 - 26.0	29.7	60.2	42.3	.240	.150	.240	1.680	.849	1.541
26.0 - 27.0	28.7	59.2	41.3	.240	.150	.240	1.680	.901	1.556
27.0 - 28.0	27.7	58.2	40.3	.240	.150	.240	1.680	.955	1.579
28.0 - 29.0	26.7	57.2	39.3	.240	.154	.240	1.680	.994	1.627
29.0 - 30.0	25.7	56.2	38.3	.240	.162	.240	1.680	1.037	1.667
30.0 - 31.0	24.7	55.2	37.3	.240	.170	.240	1.680	1.051	1.677
31.0 - 32.0	23.7	54.2	36.3	.240	.170	.240	1.680	1.090	1.680
32.0 - 33.0	22.7	53.2	35.3	.240	.172	.240	1.680	1.109	1.680
33.0 - 34.0	21.7	52.2	34.3	.240	.180	.240	1.680	1.160	1.680
34.0 - 35.0	20.7	51.2	33.3	.240	.180	.240	1.680	1.203	1.680
35.0 - 36.0	19.7	50.2	32.3	.240	.187	.240	1.680	1.261	1.680
36.0 - 37.0	18.7	49.2	31.3	.240	.200	.240	1.680	1.310	1.680
37.0 - 38.0	17.7	48.2	30.3	.240	.208	.240	1.680	1.380	1.680
38.0 - 39.0	16.7	47.2	29.3	.240	.230	.240	1.680	1.442	1.680
39.0 - 40.0	15.7	46.2	28.3	.240	.240	.240	1.680	1.484	1.680
40.0 - 41.0	14.7	45.2	27.3	.240	.240	.240	1.680	1.510	1.680
41.0 - 42.0	13.7	44.2	26.3	.240	.240	.240	1.680	1.537	1.680
42.0 - 43.0	12.7	43.2	25.3	.240	.240	.240	1.680	1.551	1.680
43.0 - 44.0	11.7	42.2	24.3	.240	.240	.240	1.680	1.579	1.680
44.0 - 45.0	10.7	41.2	23.3	.240	.240	.240	1.680	1.591	1.680
45.0 - 46.0	9.7	40.2	22.3	.240	.240	.240	1.680	1.617	1.680

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO, ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: MAIN
SUB-REGION: ILL-MO
UTILITY: UNEC

SHEET 3 OF 3

CONTRACT NO. DACW72 78 C 0013
DATE: MARCH 1980

EXHIBIT IV-3

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
MID CONTINENT AREA RELIABILITY COORDINATION AGREEMENT

SERVICE AREA APPROXIMATED BY BEA AREAS:

80	81	87	88	89	90	91	92	93	96
97	98	99	100	101	102	103	104	105	106
107	108								

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	3570.	3743.	3926.	4446.
MINING	256.	268.	280.	317.
CONSTRUCTION	2230.	2577.	2981.	3987.
MANUFACTURING	7410.	8648.	10097.	13626.
TRANSPO UTILITIES	2442.	2817.	3252.	4380.
TRADE	6124.	6994.	7995.	10695.
FINANCE	1853.	2240.	2711.	3947.
SERVICES	5813.	7177.	8865.	13336.
GOVERNMENT	5946.	7116.	8523.	12182.
TOTAL EARNINGS (MILLION $)	35652.	41629.	48640.	66927.
TOTAL PERSONAL INCOME (MILLION $)	46226.	54179.	63547.	87961.
TOTAL POPULATION (THOUSANDS)	10204.	10470.	10752.	11170.
PER CAPITA INCOME ($)	4530.	5175.	5910.	7875.
PER CAPTA INCOME RELATIVE TO U. S.	.95	.95	.96	.96

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS
REGION: MARCA
SUB-REGION: MARCA

SHEET 1 OF 1

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980
EXHIBIT V-1

ELECTRIC POWER DEMAND
MID CONTINENT AREA RELIABILITY COORDINATION AGREEMENT(MARCA)
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	10287.	.5	10652.	.5	10921.	.4	11141.	.4	11366.	.5
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	9.0	5.0	12.7	4.3	15.6	3.9	19.0	3.9	23.0	4.4
TOTAL DEMAND(THOUSAND GWH)	92.5	5.5	134.9	4.8	170.9	4.4	211.5	4.3	261.1	4.8
PEAK DEMAND(GW)	18.0	6.0	27.1	4.7	34.1	4.4	42.2	4.3	52.1	4.9
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	9.0	2.6	10.8	2.6	12.2	2.6	13.9	2.6	15.8	2.6
TOTAL DEMAND(THOUSAND GWH)	92.5	3.1	114.6	3.1	133.6	3.0	155.0	3.0	179.8	3.1
PEAK DEMAND(GW)	18.0	3.6	23.0	3.0	26.7	3.0	30.9	3.0	35.9	3.2
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	9.0	4.5	12.2	4.0	14.9	3.3	17.5	3.2	20.5	3.8
TOTAL DEMAND(THOUSAND GWH)	92.5	5.0	130.3	4.5	162.6	3.7	195.1	3.6	233.0	4.3
PEAK DEMAND(GW)	18.0	5.5	26.2	4.4	32.4	3.7	38.9	3.6	46.5	4.4
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	9.0	4.5	12.2	4.0	14.9	3.3	17.5	3.2	20.5	3.8
TOTAL DEMAND(THOUSAND GWH)	92.5	5.0	130.3	4.5	162.6	3.7	195.1	3.6	233.0	4.3
PEAK DEMAND(GW)	18.0	5.5	26.2	4.4	32.4	3.7	38.9	3.6	46.5	4.4
MARGIN(PERCENT)			17.0		17.0		17.0		17.0	
RESOURCES TO SERVE DEMAND(GW)			30.6		38.0		45.6		54.4	
LOAD FACTOR(PERCENT)	58.7		56.8		57.2		57.2		57.2	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

HARZA ENGINEERING COMPANY
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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: MARCA
SUB-REGION: MARCA

SHEET 1 OF 1

CONTRACT NO. DACW72 78-C-0013
DATE: MARCH 1980

EXHIBIT V-2

MARCA NEBRASKA PUBLIC POWER DISTRICT

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 56.4
SUMMER 58.9
WINTER 60.7

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	49.9	79.9	77.3	.010	.013	.015	.010	.018	.015
1.0 - 2.0	48.9	78.9	76.3	.016	.020	.022	.016	.041	.022
2.0 - 3.0	47.9	77.9	75.3	.049	.022	.030	.054	.068	.037
3.0 - 4.0	46.9	76.9	74.3	.078	.030	.040	.108	.088	.074
4.0 - 5.0	45.9	75.9	73.3	.103	.041	.040	.147	.117	.114
5.0 - 6.0	44.9	74.9	72.3	.137	.050	.040	.197	.140	.130
6.0 - 7.0	43.9	73.9	71.3	.143	.062	.044	.214	.161	.159
7.0 - 8.0	42.9	72.9	70.3	.150	.074	.064	.265	.189	.223
8.0 - 9.0	41.9	71.9	69.3	.150	.087	.096	.328	.230	.304
9.0 - 10.0	40.9	70.9	68.3	.155	.090	.117	.396	.272	.402
10.0 - 11.0	39.9	69.9	67.3	.160	.096	.139	.447	.300	.447
11.0 - 12.0	38.9	68.9	66.3	.160	.110	.155	.497	.328	.535
12.0 - 13.0	37.9	67.9	65.3	.168	.115	.160	.577	.357	.600
13.0 - 14.0	36.9	66.9	64.3	.170	.129	.169	.678	.411	.689
14.0 - 15.0	35.9	65.9	63.3	.174	.130	.170	.822	.456	.746
15.0 - 16.0	34.9	64.9	62.3	.180	.130	.170	.932	.534	.826
16.0 - 17.0	33.9	63.9	61.3	.180	.132	.170	1.000	.582	.870
17.0 - 18.0	32.9	62.9	60.3	.194	.140	.170	1.134	.629	.922
18.0 - 19.0	31.9	61.9	59.3	.220	.140	.170	1.253	.690	.974
19.0 - 20.0	30.9	60.9	58.3	.240	.140	.170	1.368	.737	1.013
20.0 - 21.0	29.9	59.9	57.3	.240	.150	.173	1.390	.785	1.046
21.0 - 22.0	28.9	58.9	56.3	.240	.150	.180	1.421	.877	1.093
22.0 - 23.0	27.9	57.9	55.3	.240	.160	.180	1.498	.933	1.148
23.0 - 24.0	26.9	56.9	54.3	.240	.160	.180	1.534	.978	1.191
24.0 - 25.0	25.9	55.9	53.3	.240	.160	.180	1.554	1.002	1.267
25.0 - 26.0	24.9	54.9	52.3	.240	.160	.180	1.563	1.017	1.319
26.0 - 27.0	23.9	53.9	51.3	.240	.169	.180	1.609	1.050	1.356
27.0 - 28.0	22.9	52.9	50.3	.240	.170	.194	1.630	1.093	1.385
28.0 - 29.0	21.9	51.9	49.3	.240	.172	.201	1.666	1.110	1.401
29.0 - 30.0	20.9	50.9	48.3	.240	.190	.228	1.680	1.162	1.459
30.0 - 31.0	19.9	49.9	47.3	.240	.190	.240	1.680	1.183	1.480
31.0 - 32.0	18.9	48.9	46.3	.240	.190	.240	1.680	1.200	1.512
32.0 - 33.0	17.9	47.9	45.3	.240	.202	.240	1.680	1.252	1.534
33.0 - 34.0	16.9	46.9	44.3	.240	.220	.240	1.680	1.320	1.560
34.0 - 35.0	15.9	45.9	43.3	.240	.227	.240	1.680	1.386	1.593
35.0 - 36.0	14.9	44.9	42.3	.240	.240	.240	1.680	1.414	1.610
36.0 - 37.0	13.9	43.9	41.3	.240	.240	.240	1.680	1.458	1.614
37.0 - 38.0	12.9	42.9	40.3	.240	.240	.240	1.680	1.535	1.624
38.0 - 39.0	11.9	41.9	39.3	.240	.240	.240	1.680	1.585	1.638
39.0 - 40.0	10.9	40.9	38.3	.240	.240	.240	1.680	1.615	1.666
40.0 - 41.0	9.9	39.9	37.3	.240	.240	.240	1.680	1.646	1.680
41.0 - 42.0	8.9	38.9	36.3	.240	.240	.240	1.680	1.675	1.680
42.0 - 43.0	7.9	37.9	35.3	.240	.240	.240	1.680	1.680	1.680
43.0 - 44.0	6.9	36.9	34.3	.240	.240	.240	1.680	1.680	1.680

HARZA ENGINEERING COMPANY
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CHICAGO, ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: MARCA
SUB-REGION: MARCA
UTILITY: NPPD

SHEET 1 OF 2

CONTRACT NO. DACW72 78 C 0013
DATE: MARCH 1980

EXHIBIT V-3

MARCA   IOWA ELECTRIC LIGHT AND POWER COMPANY

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 50.3
SUMMER 54.4
WINTER 70.3

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	66.7	73.6	89.8	.021	.021	.010	.027	.021	.016
1.0 - 2.0	65.7	72.6	88.8	.052	.039	.010	.083	.039	.034
2.0 - 3.0	64.7	71.6	87.8	.065	.063	.021	.132	.063	.055
3.0 - 4.0	63.7	70.6	86.8	.081	.074	.040	.181	.078	.104
4.0 - 5.0	62.7	69.6	85.8	.104	.089	.050	.246	.152	.121
5.0 - 6.0	61.7	68.6	84.8	.128	.090	.051	.291	.218	.134
6.0 - 7.0	60.7	67.6	83.8	.132	.090	.060	.335	.250	.166
7.0 - 8.0	59.7	66.6	82.8	.144	.099	.075	.414	.276	.216
8.0 - 9.0	58.7	65.6	81.8	.150	.100	.099	.430	.339	.257
9.0 - 10.0	57.7	64.6	80.8	.150	.100	.101	.453	.399	.274
10.0 - 11.0	56.7	63.6	79.8	.150	.105	.122	.500	.428	.350
11.0 - 12.0	55.7	62.6	78.8	.150	.112	.130	.536	.460	.413
12.0 - 13.0	54.7	61.6	77.8	.150	.132	.140	.556	.515	.519
13.0 - 14.0	53.7	60.6	76.8	.159	.140	.140	.587	.607	.590
14.0 - 15.0	52.7	59.6	75.8	.160	.140	.146	.647	.663	.643
15.0 - 16.0	51.7	58.6	74.8	.160	.140	.150	.695	.727	.706
16.0 - 17.0	50.7	57.6	73.8	.160	.140	.150	.740	.753	.774
17.0 - 18.0	49.7	56.6	72.8	.160	.140	.156	.773	.769	.811
18.0 - 19.0	48.7	55.6	71.8	.160	.146	.168	.803	.822	.833
19.0 - 20.0	47.7	54.6	70.8	.168	.158	.170	.872	.873	.860
20.0 - 21.0	46.7	53.6	69.8	.173	.160	.170	.936	.915	.893
21.0 - 22.0	45.7	52.6	68.8	.180	.160	.170	1.003	.954	.924
22.0 - 23.0	44.7	51.6	67.8	.180	.160	.170	1.076	.990	.941
23.0 - 24.0	43.7	50.6	66.8	.180	.160	.173	1.130	1.039	.981
24.0 - 25.0	42.7	49.6	65.8	.180	.160	.181	1.202	1.071	1.016
25.0 - 26.0	41.7	48.6	64.8	.180	.162	.190	1.295	1.092	1.048
26.0 - 27.0	40.7	47.6	63.8	.184	.170	.200	1.342	1.109	1.082
27.0 - 28.0	39.7	46.6	62.8	.190	.177	.212	1.380	1.130	1.135
28.0 - 29.0	38.7	45.6	61.8	.190	.187	.240	1.409	1.169	1.196
29.0 - 30.0	37.7	44.6	60.8	.190	.190	.240	1.431	1.190	1.238
30.0 - 31.0	36.7	43.6	59.8	.217	.195	.240	1.486	1.213	1.283
31.0 - 32.0	35.7	42.6	58.8	.237	.200	.240	1.544	1.235	1.334
32.0 - 33.0	34.7	41.6	57.8	.240	.211	.240	1.612	1.273	1.445
33.0 - 34.0	33.7	40.6	56.8	.240	.233	.240	1.645	1.320	1.483
34.0 - 35.0	32.7	39.6	55.8	.240	.240	.240	1.677	1.398	1.501
35.0 - 36.0	31.7	38.6	54.8	.240	.240	.240	1.680	1.424	1.528
36.0 - 37.0	30.7	37.6	53.8	.240	.240	.240	1.680	1.465	1.539
37.0 - 38.0	29.7	36.6	52.8	.240	.240	.240	1.680	1.542	1.542
38.0 - 39.0	28.7	35.6	51.8	.240	.240	.240	1.680	1.593	1.556
39.0 - 40.0	27.7	34.6	50.8	.240	.240	.240	1.680	1.647	1.560
40.0 - 41.0	26.7	33.6	49.8	.240	.240	.240	1.680	1.673	1.568
41.0 - 42.0	25.7	32.6	48.8	.240	.240	.240	1.680	1.680	1.587
42.0 - 43.0	24.7	31.6	47.8	.240	.240	.240	1.680	1.680	1.619
43.0 - 44.0	23.7	30.6	46.8	.240	.240	.240	1.680	1.680	1.660
44.0 - 45.0	22.7	29.6	45.8	.240	.240	.240	1.680	1.680	1.671
45.0 - 46.0	21.7	28.6	44.8	.240	.240	.240	1.680	1.680	1.680

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO, ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: MARCA
SUB-REGION: MARCA
UTILITY: IELP

SHEET 2 OF 2

CONTRACT NO. DACW72 78 C 0013
DATE: MARCH 1980

EXHIBIT V-3

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
NORTHEAST POWER COORDINATING COUNCIL (NPCC)

SERVICE AREA APPROXIMATED BY BEA AREAS:
1 2 3 4 5 6 7 8 9 12
14 1/

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	1025.	1062.	1101.	1234.
MINING	146.	158.	171.	203.
CONSTRUCTION	7778.	9062.	10559.	14445.
MANUFACTURING	34395.	38634.	43406.	56164.
TRANSPO UTILITIES	9406.	10973.	12806.	17720.
TRADE	20703.	23706.	27146.	36582.
FINANCE	9650.	11511.	13734.	19733.
SERVICES	27647.	34397.	42803.	65452.
GOVERNMENT	20495.	24833.	30092.	43988.
TOTAL EARNINGS (MILLION $)	131249.	154472.	181823.	255527.
TOTAL PERSONAL INCOME (MILLION $)	170390.	200899.	236898.	333388.
TOTAL POPULATION (THOUSANDS)	31449.	32800.	34215.	36795.
PER CAPITA INCOME ($)	5418.	6125.	6924.	9061.
PER CAPTA INCOME RELATIVE TO U. S.	1.13	1.13	1.12	1.11

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

1/ Only a portion of BEA 14 (65%) is included in the NPCC regional analysis.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **PROJECTED POPULATION, INCOME & EARNINGS** REGION: NPCC SUB-REGION: NPCC SHEET 1 OF 3	
CONTRACT NO. DACW72-78-C-0013 DATE MARCH 1980	EXHIBIT VI-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
NORTHEAST POWER COORDINATING COUNCIL
NEW ENGLAND

SERVICE AREA APPROXIMATED BY BEA AREAS:
1 2 3 4 5

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	427.	442.	457.	512.
MINING	37.	41.	45.	55.
CONSTRUCTION	2980.	3468.	4036.	5502.
MANUFACTURING	12550.	14001.	15622.	20018.
TRANSPO UTILITIES	2796.	3321.	3944.	5570.
TRADE	7246.	8330.	9576.	12991.
FINANCE	3062.	3687.	4440.	6442.
SERVICES	9779.	12315.	15509.	24040.
GOVERNMENT	7096.	8594.	10410.	15198.
TOTAL EARNINGS (MILLION $)	45976.	54262.	64042.	90332.
TOTAL PERSONAL INCOME (MILLION $)	60522.	71679.	84895.	120435.
TOTAL POPULATION (THOUSANDS)	11866.	12385.	12928.	13906.
PER CAPITA INCOME ($)	5101.	5788.	6567.	8661.
PER CAPTA INCOME RELATIVE TO U. S.	1.07	1.07	1.07	1.06

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: NPCC
SUB-REGION: NEPOOL

SHEET 2 OF 3

CONTRACT NO. DACW72 – 78 – C – 0013
DATE: MARCH 1980

EXHIBIT VI–1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
NORTHEAST POWER COORDINATING COUNCIL
NEW YORK POWER POOL

SERVICE AREA APPROXIMATED BY BEA AREAS: 1/
6 7 8 9 12 14

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	598.	621.	644.	722.
MINING	109.	117.	126.	148.
CONSTRUCTION	4797.	5594.	6523.	8943.
MANUFACTURING	21844.	24632.	27784.	36146.
TRANSPO UTILITIES	6609.	7652.	8862.	12150.
TRADE	13457.	15375.	17570.	23591.
FINANCE	6588.	7824.	9293.	13292.
SERVICES	17868.	22082.	27294.	41412.
GOVERNMENT	13399.	16238.	19682.	28790.
TOTAL EARNINGS (MILLION $)	85273.	100210.	117780.	165195.
TOTAL PERSONAL INCOME (MILLION $)	109867.	129220.	152003.	212953.
TOTAL POPULATION (THOUSANDS)	19583.	20415.	21287.	22889.
PER CAPITA INCOME ($)	5610.	6330.	7141.	9304.
PER CAPTA INCOME RELATIVE TO U. S.	1.17	1.17	1.16	1.14

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

1/ Only a portion of BEA 14 (65%) is included in the NPCC regional analysis.

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THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: NPCC
SUB-REGION: NYPP

SHEET 3 OF 3

CONTRACT NO. DACW72 – 78 – C – 0013
DATE: MARCH 1980

EXHIBIT VI–1

ELECTRIC POWER DEMAND
NORTHEAST POWER COORDINATING COUNCIL(NPCC)
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	29047.	.4	29861.	.8	31137.	.7	32241.	.7	33386.	.6
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	6.8	3.3	8.6	2.0	9.5	2.1	10.5	2.4	11.8	2.5
TOTAL DEMAND(THOUSAND GWH)	198.9	3.7	256.0	2.8	294.4	2.8	338.2	3.1	394.2	3.2
PEAK DEMAND(GW)	34.9	3.6	44.8	2.9	51.8	2.9	59.7	3.2	69.8	3.2
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	6.8	2.6	8.2	2.6	9.3	2.6	10.6	2.6	12.1	2.6
TOTAL DEMAND(THOUSAND GWH)	198.9	3.0	245.0	3.5	290.4	3.3	341.9	3.3	402.6	3.3
PEAK DEMAND(GW)	34.9	3.0	42.9	3.6	51.1	3.4	60.4	3.4	71.3	3.3
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	6.8	4.5	9.3	4.0	11.4	3.3	13.4	3.2	15.6	3.8
TOTAL DEMAND(THOUSAND GWH)	198.9	4.9	278.5	4.9	353.4	4.0	430.4	3.9	521.8	4.5
PEAK DEMAND(GW)	34.9	4.9	48.7	5.0	62.2	4.1	76.0	4.0	92.4	4.5
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	6.8	3.4	8.7	2.5	9.8	2.5	11.1	2.7	12.7	2.9
TOTAL DEMAND(THOUSAND GWH)	198.9	3.9	259.2	3.4	306.1	3.2	359.0	3.5	425.5	3.5
PEAK DEMAND(GW)	34.9	3.8	45.4	3.5	53.9	3.3	63.4	3.5	75.3	3.6
MARGIN(PERCENT)			27.1		27.2		26.8		26.4	
RESOURCES TO SERVE DEMAND(GW)			57.7		68.5		80.4		95.2	
LOAD FACTOR(PERCENT)	65.1		65.2		64.9		64.7		64.5	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: NPCC
SUB-REGION: NPCC

SHEET 1 OF 3

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT VI-2

ELECTRIC POWER DEMAND
NEW ENGLAND SUB-REGION
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	11280.	.7	11844.	.9	12387.	.7	12826.	.7	13282.	.7
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	7.3	4.5	10.0	2.4	11.3	2.4	12.7	2.9	14.6	3.2
TOTAL DEMAND(THOUSAND GWH)	82.8	5.3	118.6	3.3	139.4	3.1	162.7	3.6	194.4	4.0
PEAK DEMAND(GW)	15.1	5.2	21.5	3.1	25.1	3.1	29.3	3.6	35.0	3.9
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	7.3	2.6	8.8	2.6	10.0	2.6	11.4	2.6	12.9	2.6
TOTAL DEMAND(THOUSAND GWH)	82.8	3.3	104.1	3.5	123.7	3.3	145.7	3.3	171.5	3.4
PEAK DEMAND(GW)	15.1	3.2	18.9	3.4	22.3	3.3	26.2	3.3	30.9	3.3
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	7.3	4.5	10.0	4.0	12.2	3.3	14.3	3.2	16.7	3.8
TOTAL DEMAND(THOUSAND GWH)	82.8	5.2	118.3	4.9	150.5	4.0	183.4	3.9	222.3	4.6
PEAK DEMAND(GW)	15.1	5.1	21.4	4.8	27.1	4.0	33.0	3.9	40.0	4.5
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	7.3	4.5	10.0	2.4	11.3	2.4	12.7	2.9	14.6	3.2
TOTAL DEMAND(THOUSAND GWH)	82.8	5.2	118.3	3.3	139.4	3.1	162.7	3.6	194.4	4.0
PEAK DEMAND(GW)	15.1	5.1	21.4	3.2	25.1	3.1	29.3	3.6	35.0	3.9
MARGIN(PERCENT)			20.0		23.0		23.0		23.0	
RESOURCES TO SERVE DEMAND(GW)			25.7		30.9		36.0		43.0	
LOAD FACTOR(PERCENT)	62.6		63.0		63.4		63.4		63.4	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: NPCC
SUB-REGION: NEPOOL

SHEET 2 OF 3

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT VI-2

ELECTRIC POWER DEMAND
NEW YORK SUB-REGION
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	17767.	.2	18017.	.8	18750.	.7	19415.	.7	20104.	.6
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	6.5	2.2	7.6	1.6	8.3	1.8	9.0	1.9	9.9	1.9
TOTAL DEMAND(THOUSAND GWH)	116.1	2.4	137.4	2.4	155.0	2.5	175.5	2.6	199.9	2.5
PEAK DEMAND(GW)	20.4	2.9	24.9	2.4	28.0	2.5	31.7	2.6	36.1	2.6
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	6.5	2.6	7.8	2.6	8.9	2.6	10.1	2.6	11.5	2.6
TOTAL DEMAND(THOUSAND GWH)	116.1	2.8	140.9	3.4	166.7	3.3	196.3	3.3	231.1	3.2
PEAK DEMAND(GW)	20.4	3.3	25.5	3.4	30.1	3.3	35 5	3.3	41.7	3.3
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	6.5	4.5	8.9	4.0	10.8	3.3	12.7	3.2	14.9	3.8
TOTAL DEMAND(THOUSAND GWH)	116.1	4.7	160.2	4.8	202.9	4.0	247.1	3.9	299.5	4.4
PEAK DEMAND(GW)	20.4	5.2	29.0	4.8	36.6	4.0	44.6	3.9	54.1	4.5
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	6.5	2.6	7.8	2.6	8.9	2.6	10.1	2.6	11.5	2.6
TOTAL DEMAND(THOUSAND GWH)	116.1	2.8	140.9	3.4	166.7	3.3	196.3	3.3	231.1	3.2
PEAK DEMAND(GW)	20.4	3.3	25.5	3.4	30.1	3.3	35.5	3.3	41.7	3.3
MARGIN(PERCENT)			25.0		25.0		25.0		25.0	
RESOURCES TO SERVE DEMAND(GW)			31.9		37.6		44.3		52.2	
LOAD FACTOR(PERCENT)	65.0		63.0		63.2		63.2		63.2	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: NPCC
SUB-REGION: NYPP

SHEET 3 OF 3

CONTRACT NO. DACW72 78 C 0013
DATE MARCH 1980

EXHIBIT VI-2

NPCC NEPOOL NEW ENGLAND POWER EXCHANGE(NEPEX)

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 60.6
SUMMER 64.5
WINTER 70.2

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	79.5	86.8	91.2	.016	.019	.010	.016	.026	.018
1.0 - 2.0	78.5	85.8	90.2	.039	.049	.012	.039	.086	.041
2.0 - 3.0	77.5	84.8	89.2	.072	.067	.020	.084	.154	.050
3.0 - 4.0	76.5	83.8	88.2	.103	.070	.024	.134	.198	.072
4.0 - 5.0	75.5	82.8	87.2	.120	.079	.030	.198	.248	.113
5.0 - 6.0	74.5	81.8	86.2	.120	.082	.030	.268	.289	.151
6.0 - 7.0	73.5	80.8	85.2	.120	.090	.035	.315	.313	.194
7.0 - 8.0	72.5	79.8	84.2	.126	.097	.065	.393	.345	.302
8.0 - 9.0	71.5	78.8	83.2	.130	.110	.096	.454	.393	.425
9.0 - 10.0	70.5	77.8	82.2	.130	.114	.110	.493	.437	.500
10.0 - 11.0	69.5	76.8	81.2	.139	.129	.123	.556	.498	.547
11.0 - 12.0	68.5	75.8	80.2	.141	.130	.130	.610	.524	.619
12.0 - 13.0	67.5	74.8	79.2	.150	.135	.130	.647	.546	.669
13.0 - 14.0	66.5	73.8	78.2	.150	.140	.130	.669	.570	.712
14.0 - 15.0	65.5	72.8	77.2	.150	.140	.130	.698	.616	.726
15.0 - 16.0	64.5	71.8	76.2	.150	.140	.137	.737	.630	.746
16.0 - 17.0	63.5	70.8	75.2	.150	.140	.140	.768	.673	.774
17.0 - 18.0	62.5	69.8	74.2	.150	.146	.147	.804	.701	.812
18.0 - 19.0	61.5	68.8	73.2	.154	.150	.150	.827	.716	.831
19.0 - 20.0	60.5	67.8	72.2	.160	.150	.150	.859	.720	.851
20.0 - 21.0	59.5	66.8	71.2	.160	.150	.150	.878	.723	.867
21.0 - 22.0	58.5	65.8	70.2	.160	.150	.150	.906	.731	.872
22.0 - 23.0	57.5	64.8	69.2	.160	.151	.153	.915	.741	.908
23.0 - 24.0	56.5	63.8	68.2	.166	.160	.160	.960	.770	.943
24.0 - 25.0	55.5	62.8	67.2	.170	.160	.160	1.000	.797	.969
25.0 - 26.0	54.5	61.8	66.2	.171	.168	.160	1.032	.847	.980
26.0 - 27.0	53.5	60.8	65.2	.180	.170	.160	1.067	.860	1.005
27.0 - 28.0	52.5	59.8	64.2	.180	.170	.160	1.082	.881	1.038
28.0 - 29.0	51.5	58.8	63.2	.180	.170	.160	1.104	.925	1.062
29.0 - 30.0	50.5	57.8	62.2	.180	.170	.160	1.121	.999	1.080
30.0 - 31.0	49.5	56.8	61.2	.182	.170	.161	1.171	1.074	1.103
31.0 - 32.0	48.5	55.8	60.2	.191	.170	.180	1.226	1.119	1.130
32.0 - 33.0	47.5	54.8	59.2	.203	.170	.180	1.288	1.130	1.132
33.0 - 34.0	46.5	53.8	58.2	.210	.170	.180	1.369	1.150	1.155
34.0 - 35.0	45.5	52.8	57.2	.225	.170	.180	1.442	1.189	1.195
35.0 - 36.0	44.5	51.8	56.2	.240	.184	.180	1.531	1.220	1.219
36.0 - 37.0	43.5	50.8	55.2	.240	.190	.180	1.553	1.242	1.273
37.0 - 38.0	42.5	49.8	54.2	.240	.190	.180	1.568	1.267	1.336
38.0 - 39.0	41.5	48.8	53.2	.240	.195	.180	1.579	1.324	1.408
39.0 - 40.0	40.5	47.8	52.2	.240	.200	.180	1.605	1.373	1.453
40.0 - 41.0	39.5	46.8	51.2	.240	.209	.180	1.637	1.428	1.494
41.0 - 42.0	38.5	45.8	50.2	.240	.221	.181	1.643	1.462	1.514
42.0 - 43.0	37.5	44.8	49.2	.240	.239	.190	1.665	1.489	1.545
43.0 - 44.0	36.5	43.8	48.2	.240	.240	.195	1.680	1.524	1.555
44.0 - 45.0	35.5	42.8	47.2	.240	.240	.200	1.680	1.571	1.561
45.0 - 46.0	34.5	41.8	46.2	.240	.240	.211	1.680	1.628	1.581

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THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: NPCC
SUB-REGION: NEPOOL
UTILITY: NEPEX

SHEET 1 OF 3

CONTRACT NO. DACW72 - 78 - C - 0013

DATE: MARCH 1980

EXHIBIT VI-3

NPCC NYPP CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 44.0
SUMMER 63.6
WINTER 47.3

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	62.5	91.1	65.4	.024	.018	.010	.024	.018	.010
1.0 - 2.0	61.5	90.1	64.4	.070	.028	.020	.070	.030	.020
2.0 - 3.0	60.5	89.1	63.4	.070	.040	.035	.080	.056	.071
3.0 - 4.0	59.5	88.1	62.4	.076	.049	.063	.117	.081	.135
4.0 - 5.0	58.5	87.1	61.4	.083	.060	.080	.206	.117	.263
5.0 - 6.0	57.5	86.1	60.4	.090	.062	.094	.303	.183	.405
6.0 - 7.0	56.5	85.1	59.4	.090	.072	.100	.347	.238	.478
7.0 - 8.0	55.5	84.1	58.4	.101	.080	.100	.371	.291	.502
8.0 - 9.0	54.5	83.1	57.4	.110	.080	.110	.388	.318	.538
9.0 - 10.0	53.5	82.1	56.4	.120	.080	.110	.439	.357	.550
10.0 - 11.0	52.5	81.1	55.4	.130	.086	.111	.483	.384	.583
11.0 - 12.0	51.5	80.1	54.4	.130	.095	.120	.517	.405	.632
12.0 - 13.0	50.5	79.1	53.4	.130	.100	.128	.552	.425	.657
13.0 - 14.0	49.5	78.1	52.4	.138	.100	.130	.599	.440	.677
14.0 - 15.0	48.5	77.1	51.4	.140	.100	.135	.627	.452	.707
15.0 - 16.0	47.5	76.1	50.4	.140	.107	.140	.659	.471	.720
16.0 - 17.0	46.5	75.1	49.4	.140	.116	.140	.682	.486	.730
17.0 - 18.0	45.5	74.1	48.4	.140	.120	.140	.724	.502	.763
18.0 - 19.0	44.5	73.1	47.4	.155	.131	.140	.765	.532	.838
19.0 - 20.0	43.5	72.1	46.4	.160	.140	.143	.801	.574	.889
20.0 - 21.0	42.5	71.1	45.4	.160	.140	.150	.853	.598	.914
21.0 - 22.0	41.5	70.1	44.4	.160	.140	.150	.906	.613	.957
22.0 - 23.0	40.5	69.1	43.4	.160	.150	.159	.944	.641	.979
23.0 - 24.0	39.5	68.1	42.4	.160	.150	.160	.996	.669	.989
24.0 - 25.0	38.5	67.1	41.4	.169	.150	.160	1.031	.689	1.028
25.0 - 26.0	37.5	66.1	40.4	.170	.150	.160	1.048	.706	1.060
26.0 - 27.0	36.5	65.1	39.4	.170	.150	.160	1.064	.710	1.074
27.0 - 28.0	35.5	64.1	38.4	.173	.150	.160	1.099	.720	1.119
28.0 - 29.0	34.5	63.1	37.4	.183	.157	.170	1.189	.746	1.161
29.0 - 30.0	33.5	62.1	36.4	.190	.160	.173	1.251	.760	1.190
30.0 - 31.0	32.5	61.1	35.4	.190	.169	.180	1.276	.782	1.239
31.0 - 32.0	31.5	60.1	34.4	.199	.170	.180	1.326	.801	1.257
32.0 - 33.0	30.5	59.1	33.4	.213	.170	.180	1.405	.814	1.295
33.0 - 34.0	29.5	58.1	32.4	.231	.170	.180	1.499	.831	1.361
34.0 - 35.0	28.5	57.1	31.4	.240	.170	.180	1.584	.858	1.434
35.0 - 36.0	27.5	56.1	30.4	.240	.170	.189	1.631	.906	1.518
36.0 - 37.0	26.5	55.1	29.4	.240	.170	.199	1.668	.964	1.558
37.0 - 38.0	25.5	54.1	28.4	.240	.170	.203	1.680	1.017	1.590
38.0 - 39.0	24.5	53.1	27.4	.240	.170	.214	1.680	1.090	1.631
39.0 - 40.0	23.5	52.1	26.4	.240	.171	.238	1.680	1.127	1.676
40.0 - 41.0	22.5	51.1	25.4	.240	.180	.240	1.680	1.168	1.680
41.0 - 42.0	21.5	50.1	24.4	.240	.188	.240	1.680	1.214	1.680
42.0 - 43.0	20.5	49.1	23.4	.240	.190	.240	1.680	1.270	1.680
43.0 - 44.0	19.5	48.1	22.4	.240	.194	.240	1.680	1.308	1.680
44.0 - 45.0	18.5	47.1	21.4	.240	.200	.240	1.680	1.349	1.680
45.0 - 46.0	17.5	46.1	20.4	.240	.200	.240	1.680	1.410	1.680

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THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **SEASONAL ENERGY REQUIREMENTS** REGION: NPCC SUB-REGION: NYPP UTILITY: COEN SHEET 2 OF 3	
CONTRACT NO. DACW72 - 78 - C - 0013 DATE: MARCH 1980	EXHIBIT VI-3

NPCC NYPP NIAGRA MOHAWK SYSTEM

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 66.7
SUMMER 65.9
WINTER 75.7

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	82.3	83.5	94.5	.010	.020	.010	.021	.044	.010
1.0 - 2.0	81.3	82.5	93.5	.016	.038	.010	.073	.090	.029
2.0 - 3.0	80.3	81.5	92.5	.056	.065	.020	.176	.137	.065
3.0 - 4.0	79.3	80.5	91.5	.070	.078	.021	.244	.189	.093
4.0 - 5.0	78.3	79.5	90.5	.097	.080	.032	.387	.279	.128
5.0 - 6.0	77.3	78.5	89.5	.119	.088	.040	.442	.355	.177
6.0 - 7.0	76.3	77.5	88.5	.137	.103	.040	.503	.422	.215
7.0 - 8.0	75.3	76.5	87.5	.140	.112	.060	.534	.470	.320
8.0 - 9.0	74.3	75.5	86.5	.140	.130	.087	.560	.515	.412
9.0 - 10.0	73.3	74.5	85.5	.143	.130	.108	.591	.543	.488
10.0 - 11.0	72.3	73.5	84.5	.154	.130	.134	.639	.603	.582
11.0 - 12.0	71.3	72.5	83.5	.160	.132	.140	.672	.639	.650
12.0 - 13.0	70.3	71.5	82.5	.160	.144	.140	.701	.675	.699
13.0 - 14.0	69.3	70.5	81.5	.160	.150	.140	.728	.692	.725
14.0 - 15.0	68.3	69.5	80.5	.160	.150	.148	.771	.707	.752
15.0 - 16.0	67.3	68.5	79.5	.160	.150	.150	.795	.734	.764
16.0 - 17.0	66.3	67.5	78.5	.160	.150	.160	.811	.740	.791
17.0 - 18.0	65.3	66.5	77.5	.170	.150	.160	.833	.750	.811
18.0 - 19.0	64.3	65.5	76.5	.171	.150	.160	.888	.773	.844
19.0 - 20.0	63.3	64.5	75.5	.180	.150	.160	.935	.788	.878
20.0 - 21.0	62.3	63.5	74.5	.180	.160	.160	.969	.828	.907
21.0 - 22.0	61.3	62.5	73.5	.180	.170	.160	1.009	.886	.935
22.0 - 23.0	60.3	61.5	72.5	.180	.170	.160	1.054	.940	.961
23.0 - 24.0	59.3	60.5	71.5	.182	.170	.166	1.091	.986	.988
24.0 - 25.0	58.3	59.5	70.5	.190	.170	.173	1.138	1.033	1.030
25.0 - 26.0	57.3	58.5	69.5	.197	.170	.180	1.185	1.076	1.042
26.0 - 27.0	56.3	57.5	68.5	.210	.170	.180	1.257	1.143	1.087
27.0 - 28.0	55.3	56.5	67.5	.222	.170	.180	1.338	1.186	1.110
28.0 - 29.0	54.3	55.5	66.5	.240	.170	.180	1.400	1.234	1.124
29.0 - 30.0	53.3	54.5	65.5	.240	.180	.180	1.460	1.292	1.161
30.0 - 31.0	52.3	53.5	64.5	.240	.180	.181	1.515	1.327	1.203
31.0 - 32.0	51.3	52.5	63.5	.240	.180	.196	1.573	1.373	1.269
32.0 - 33.0	50.3	51.5	62.5	.240	.186	.201	1.600	1.446	1.329
33.0 - 34.0	49.3	50.5	61.5	.240	.194	.212	1.615	1.493	1.404
34.0 - 35.0	48.3	49.5	60.5	.240	.207	.235	1.625	1.533	1.483
35.0 - 36.0	47.3	48.5	59.5	.240	.231	.240	1.632	1.564	1.518
36.0 - 37.0	46.3	47.5	58.5	.240	.240	.240	1.650	1.592	1.534
37.0 - 38.0	45.3	46.5	57.5	.240	.240	.240	1.680	1.631	1.554
38.0 - 39.0	44.3	45.5	56.5	.240	.240	.240	1.680	1.663	1.562
39.0 - 40.0	43.3	44.5	55.5	.240	.240	.240	1.680	1.680	1.580
40.0 - 41.0	42.3	43.5	54.5	.240	.240	.240	1.680	1.680	1.613
41.0 - 42.0	41.3	42.5	53.5	.240	.240	.240	1.680	1.680	1.630
42.0 - 43.0	40.3	41.5	52.5	.240	.240	.240	1.680	1.680	1.639
43.0 - 44.0	39.3	40.5	51.5	.240	.240	.240	1.680	1.680	1.656
44.0 - 45.0	38.3	39.5	50.5	.240	.240	.240	1.680	1.680	1.679
45.0 - 46.0	37.3	38.5	49.5	.240	.240	.240	1.680	1.680	1.680

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: NPCC
SUB-REGION: NYPP
UTILITY: NIMP

SHEET 3 OF 3

CONTRACT NO. DACW72-78-C-0013

DATE: MARCH 1980

EXHIBIT VI-3

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
SOUTHEASTERN ELECTRIC RELIABLITY
COUNCIL (SERC)

SERVICE AREA APPROXIMATED BY BEA AREAS:

18	21	22	23	24	25	26	27	28	29
30	31	32	33	34	35	36	37	38	39
40	41	42	43	44	45	46	47	48	49
50	136	137							

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	3807.	3976.	4155.	4695.
MINING	450.	496.	549.	666.
CONSTRUCTION	8207.	9896.	11937.	16826.
MANUFACTURING	28237.	33818.	40519.	56308.
TRANSPO UTILITIES	8345.	10207.	12491.	18204.
TRADE	20100.	23981.	28624.	40373.
FINANCE	6984.	8889.	11320.	17541.
SERVICES	21779.	27963.	35914.	56958.
GOVERNMENT	28929.	35456.	43489.	63679.
TOTAL EARNINGS (MILLION $)	126851.	154808.	189012.	275264.
TOTAL PERSONAL INCOME (MILLION $)	160986.	198421.	244690.	362556.
TOTAL POPULATION (THOUSANDS)	38607.	41529.	44714.	49379.
PER CAPITA INCOME ($)	4170.	4778.	5472.	7342.
PER CAPTA INCOME RELATIVE TO U. S.	.87	.88	.89	.90

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
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THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: SERC
SUB–REGION: SERC

SHEET 1 OF 5

CONTRACT NO. DACW72 – 78 – C – 0013
DATE: MARCH 1980

EXHIBIT VII–1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
VIRGINIA CAROLINAS SUBREGION

SERVICE AREA APPROXIMATED BY BEA AREAS:
18 1/ 21 22 23 24 25 26 27 28 29
30 31

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	1123.	1165.	1210.	1358.
MINING	70.	79.	90.	112.
CONSTRUCTION	3208.	3871.	4673.	6618.
MANUFACTURING	11410.	13663.	16368.	22758.
TRANSPO UTILITIES	2967.	3628.	4440.	6482.
TRADE	7305.	8719.	10412.	14716.
FINANCE	2580.	3260.	4121.	6304.
SERVICES	9041.	11636.	14980.	23839.
GOVERNMENT	15123.	18371.	22329.	32274.
TOTAL EARNINGS (MILLION $)	52832.	64438.	78628.	114472.
TOTAL PERSONAL INCOME (MILLION $)	63515.	78101.	96080.	141769.
TOTAL POPULATION (THOUSANDS)	14416.	15496.	16669.	18413.
PER CAPITA INCOME ($)	4406.	5040.	5764.	7699.
PER CAPTA INCOME RELATIVE TO U. S.	.92	.93	.93	.94

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

1/ BEA 18 includes the Washington D.C. Metropolitan area which actually is a part of MAAC.

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CONTRACT NO. DACW72-78-C-0013 DATE: MARCH 1980	EXHIBIT VII-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
TENNESSEE VALLEY AUTHORITY

SERVICE AREA APPROXIMATED BY BEA AREAS:
46 47 48 49 50

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	823.	846.	869.	962.
MINING	121.	133.	146.	177.
CONSTRUCTION	982.	1190.	1441.	2056.
MANUFACTURING	5507.	6636.	7997.	11219.
TRANSPO UTILITIES	909.	1108.	1350.	1970.
TRADE	2801.	3330.	3961.	5566.
FINANCE	839.	1061.	1341.	2055.
SERVICES	2866.	3687.	4744.	7556.
GOVERNMENT	3257.	4032.	4990.	7400.
TOTAL EARNINGS (MILLION $)	18107.	22045.	26844.	38964.
TOTAL PERSONAL INCOME (MILLION $)	22631.	27724.	33972.	49794.
TOTAL POPULATION (THOUSANDS)	6171.	6554.	6962.	7502.
PER CAPITA INCOME ($)	3667.	4230.	4879.	6637.
PER CAPTA INCOME RELATIVE TO U. S.	.77	.78	.79	.81

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: SERC
SUB-REGION: TVA

SHEET 3 OF 5

CONTRACT NO DACW72 - 78 - C - 0013
DATE MARCH 1980

EXHIBIT VII-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
SOUTHERN COMPANIES SUBREGION

SERVICE AREA APPROXIMATED BY BEA AREAS:
32 33 39 40 41 42 43 44 45 136
137

	************** YEAR **************			
SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	1005.	1062.	1122.	1285.
MINING	171.	186.	204.	243.
CONSTRUCTION	1698.	2033.	2435.	3398.
MANUFACTURING	7654.	9065.	10739.	14667.
TRANSPO UTILITIES	2136.	2577.	3110.	4432.
TRADE	4822.	5701.	6742.	9356.
FINANCE	1544.	1938.	2434.	3737.
SERVICES	4110.	5227.	6653.	10418.
GOVERNMENT	5808.	7074.	8625.	12473.
TOTAL EARNINGS (MILLION $)	28952.	34891.	42068.	60013.
TOTAL PERSONAL INCOME (MILLION $)	35716.	43327.	52585.	75817.
TOTAL POPULATION (THOUSANDS)	9314.	9816.	10353.	11018.
PER CAPITA INCOME ($)	3835.	4414.	5079.	6881.
PER CAPTA INCOME RELATIVE TO U. S.	.80	.81	.82	.84

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: SERC
SUB–REGION: SOUTHERN

SHEET 4 OF 5

CONTRACT NO DACW72 – 78 – C – 0013
DATE MARCH 1980

EXHIBIT VII–1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
FLORIDA SUBREGION

SERVICE AREA APPROXIMATED BY BEA AREAS:
34 35 36 37 38

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	857.	904.	953.	1090.
MINING	88.	98.	109.	133.
CONSTRUCTION	2318.	2802.	3388.	4754.
MANUFACTURING	3665.	4453.	5414.	7663.
TRANSPO UTILITIES	2333.	2895.	3591.	5319.
TRADE	5172.	6231.	7509.	10732.
FINANCE	2020.	2630.	3423.	5445.
SERVICES	5763.	7413.	9537.	15145.
GOVERNMENT	4741.	5980.	7545.	11532.
TOTAL EARNINGS (MILLION $)	26959.	33435.	41472.	61815.
TOTAL PERSONAL INCOME (MILLION $)	39125.	49269.	62053.	95177.
TOTAL POPULATION (THOUSANDS)	8707.	9663.	10729.	12445.
PER CAPITA INCOME ($)	4494.	5099.	5784.	7648.
PER CAPTA INCOME RELATIVE TO U. S.	.94	.94	.94	.94

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: SERC

SUB-REGION: FLORIDA

SHEET 5 OF 5

CONTRACT NO. DACW72-78-C-0013

DATE: MARCH 1980

EXHIBIT VII-1

ELECTRIC POWER DEMAND
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL(SERC)
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	37911.	1.6	42391.	1.5	45671.	1.0	47961.	1.0	50381.	1.3
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	12.0	4.1	15.9	2.9	18.3	3.4	21.7	3.4	25.6	3.5
TOTAL DEMAND(THOUSAND GWH)	453.2	5.8	673.4	4.5	838.0	4.4	1040.2	4.4	1289.7	4.9
PEAK DEMAND(GW)	80.5	6.5	125.5	4.7	157.7	4.4	195.8	4.4	242.8	5.1
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	12.0	2.6	14.3	2.6	16.2	2.6	18.4	2.6	20.8	2.6
TOTAL DEMAND(THOUSAND GWH)	453.2	4.2	604.5	4.1	738.8	3.6	880.1	3.6	1048.9	3.9
PEAK DEMAND(GW)	80.5	4.9	112.7	4.3	139.0	3.6	165.7	3.6	197.5	4.2
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	12.0	4.5	16.2	4.0	19.7	3.3	23.1	3.2	27.0	3.8
TOTAL DEMAND(THOUSAND GWH)	453.2	6.1	687.3	5.5	898.9	4.3	1108.0	4.2	1359.5	5.1
PEAK DEMAND(GW)	80.5	6.9	128.1	5.7	169.2	4.3	208.6	4.2	255.9	5.4
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	12.0	4.1	15.8	3.1	18.4	3.0	21.4	2.7	24.5	3.3
TOTAL DEMAND(THOUSAND GWH)	453.2	5.7	669.3	4.7	842.0	4.0	1026.8	3.7	1233.0	4.7
PEAK DEMAND(GW)	80.5	6.5	124.7	4.9	158.4	4.1	193.3	3.7	232.1	4.9
MARGIN(PERCENT)			26.6		23.2		21.4		20.6	
RESOURCES TO SERVE DEMAND(GW)			157.9		195.2		234.6		280.1	
LOAD FACTOR(PERCENT)	64.3		61.3		60.7		60.6		60.6	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: SERC
SUB-REGION: SERC

SHEET 1 OF 5

CONTRACT NO. DACW72-78-C-0013
DATE: MARCH 1980

EXHIBIT VII-2

ELECTRIC POWER DEMAND
VIRGINIA-CAROLINAS SUB-REGION
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	14105.	1.4	15547.	1.5	16749.	1.0	17603.	1.0	18501.	1.2
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	10.1	4.9	14.2	3.9	17.2	4.2	21.1	4.1	25.8	4.3
TOTAL DEMAND(THOUSAND GWH)	143.0	6.4	220.4	5.5	287.5	5.2	371.3	5.1	477.3	5.6
PEAK DEMAND(GW)	25.9	6.7	40.7	5.5	53.2	5.2	68.7	5.1	88.3	5.7
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	10.1	2.6	12.1	2.6	13.8	2.6	15.7	2.6	17.8	2.6
TOTAL DEMAND(THOUSAND GWH)	143.0	4.0	188.6	4.1	231.1	3.6	276.1	3.6	329.9	3.9
PEAK DEMAND(GW)	25.9	4.3	34.8	4.2	42.7	3.6	51.1	3.6	61.0	4.0
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	10.1	4.5	13.8	4.0	16.8	3.3	19.7	3.2	23.1	3.8
TOTAL DEMAND(THOUSAND GWH)	143.0	6.0	214.5	5.6	281.1	4.3	347.6	4.2	427.6	5.1
PEAK DEMAND(GW)	25.9	6.3	39.6	5.6	52.0	4.3	64.3	4.2	79.1	5.2
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	10.1	4.5	13.8	4.0	16.8	3.3	19.7	3.2	23.1	3.8
TOTAL DEMAND(THOUSAND GWH)	143.0	6.0	214.5	5.6	281.1	4.3	347.6	4.2	427.6	5.1
PEAK DEMAND(GW)	25.9	6.3	39.6	5.6	52.0	4.3	64.3	4.2	79.1	5.2
MARGIN(PERCENT)			25.0		21.0		18.0		17.0	
RESOURCES TO SERVE DEMAND(GW)			49.5		62.9		75.9		92.6	
LOAD FACTOR(PERCENT)	63.0		61.8		61.7		61.7		61.7	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: SERC
SUB--REGION: VACAR

SHEET 2 OF 5

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980
EXHIBIT VII-2

ELECTRIC POWER DEMAND
TENNESSEE VALLEY SUB-REGION
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	6027.	1.3	6597.	1.2	7003.	.7	7251.	.7	7509.	1.0
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	20.4	4.7	28.1	2.2	31.3	2.4	35.2	1.9	38.7	3.0
TOTAL DEMAND(THOUSAND GWH)	122.8	6.1	185.3	3.4	219.4	3.1	255.5	2.6	290.5	4.0
PEAK DEMAND(GW)	21.5	6.3	33.0	3.7	39.5	3.1	46.0	2.6	52.3	4.1
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	20.4	2.6	24.4	2.6	27.7	2.6	31.5	2.6	35.8	2.6
TOTAL DEMAND(THOUSAND GWH)	122.8	3.9	160.9	3.8	194.2	3.3	228.6	3.3	269.1	3.6
PEAK DEMAND(GW)	21.5	4.2	28.6	4.1	35.0	3.3	41.2	3.3	48.5	3.8
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	20.4	4.5	27.7	4.0	33.7	3.3	39.7	3.2	46.4	3.8
TOTAL DEMAND(THOUSAND GWH)	122.8	5.9	182.9	5.2	236.2	4.0	287.7	3.9	348.8	4.9
PEAK DEMAND(GW)	21.5	6.1	32.6	5.5	42.5	4.0	51.8	3.9	62.8	5.0
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	20.4	4.5	27.7	2.5	31.3	2.4	35.2	1.9	38.7	3.0
TOTAL DEMAND(THOUSAND GWH)	122.8	5.9	182.9	3.7	219.4	3.1	255.5	2.6	290.5	4.0
PEAK DEMAND(GW)	21.5	6.1	32.6	3.9	39.5	3.1	46.0	2.6	52.3	4.1
MARGIN(PERCENT)			25.0		22.0		22.0		22.0	
RESOURCES TO SERVE DEMAND(GW)			40.7		48.2		56.1		63.8	
LOAD FACTOR(PERCENT)	65.2		64.1		63.4		63.4		63.4	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: SERC
SUB-REGION: TVA

SHEET 3 OF 5

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980
EXHIBIT VII-2

ELECTRIC POWER DEMAND
SOUTHERN SUB-REGION
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	9401.	1.2	10220.	1.1	10794.	.6	11122.	.6	11460.	.9
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	10.9	4.4	14.7	3.4	17.4	4.0	21.2	4.1	25.9	4.0
TOTAL DEMAND(THOUSAND GWH)	102.5	5.6	150.3	4.6	188.0	4.6	235.8	4.7	296.6	4.9
PEAK DEMAND(GW)	20.3	5.2	29.0	4.5	36.2	4.6	45.4	4.7	57.1	4.8
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	10.9	2.6	13.0	2.6	14.8	2.6	16.9	2.6	19.2	2.6
TOTAL DEMAND(THOUSAND GWH)	102.5	3.8	133.4	3.7	160.1	3.2	187.6	3.2	219.8	3.5
PEAK DEMAND(GW)	20.3	3.4	25.7	3.7	30.8	3.2	36.1	3.2	42.3	3.4
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	10.9	4.5	14.8	4.0	18.1	3.3	21.2	3.2	24.9	3.8
TOTAL DEMAND(THOUSAND GWH)	102.5	5.8	151.6	5.1	194.9	3.9	236.2	3.8	284.8	4.8
PEAK DEMAND(GW)	20.3	5.4	29.3	5.1	37.5	3.9	45.5	3.8	54.8	4.6
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	10.9	4.4	14.7	3.4	17.4	4.0	21.2	3.2	24.9	3.8
TOTAL DEMAND(THOUSAND GWH)	102.5	5.6	150.3	4.6	188.0	4.6	235.8	3.8	284.8	4.8
PEAK DEMAND(GW)	20.3	5.2	29.0	4.5	36.2	4.6	45.4	3.8	54.8	4.6
MARGIN(PERCENT)			20.0		17.0		17.0		17.0	
RESOURCES TO SERVE DEMAND(GW)			34.8		42.4		53.1		64.2	
LOAD FACTOR(PERCENT)	57.6		59.2		59.3		59.3		59.3	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: SERC
SUB-REGION: SOUTHERN

SHEET 4 OF 5

CONTRACT NO. DACW72 78-C-0013
DATE MARCH 1980

EXHIBIT VII-2

ELECTRIC POWER DEMAND
FLORDIA SUB-REGION
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	8378.	2.6	10027.	2.1	11125.	1.5	11985.	1.5	12911.	2.0
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	10.1	2.1	11.7	1.9	12.9	2.9	14.8	3.3	17.5	2.5
TOTAL DEMAND(THOUSAND GWH)	84.9	4.7	117.4	4.0	143.0	4.4	177.5	4.9	225.4	4.5
PEAK DEMAND(GW)	16.9	6.0	25.4	4.1	31.1	4.4	38.6	4.9	49.0	5.0
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	10.1	2.6	12.1	2.6	13.8	2.6	15.7	2.6	17.8	2.6
TOTAL DEMAND(THOUSAND GWH)	84.9	5.3	121.6	4.8	153.4	4.1	187.9	4.1	230.1	4.6
PEAK DEMAND(GW)	16.9	6.5	26.3	4.9	33.4	4.1	40.9	4.1	50.0	5.1
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	10.1	4.5	13.8	4.0	16.8	3.3	19.7	3.2	23.1	3.8
TOTAL DEMAND(THOUSAND GWH)	84.9	7.2	138.3	6.2	186.7	4.8	236.5	4.7	298.3	5.9
PEAK DEMAND(GW)	16.9	8.5	29.9	6.3	40.6	4.8	51.4	4.7	64.9	6.3
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	10.1	2.6	12.1	2.6	13.8	2.6	15.7	2.6	17.8	2.6
TOTAL DEMAND(THOUSAND GWH)	84.9	5.3	121.6	4.8	153.4	4.1	187.9	4.1	230.1	4.6
PEAK DEMAND(GW)	16.9	6.5	26.3	4.9	33.4	4.1	40.9	4.1	50.0	5.1
MARGIN(PERCENT)			25.0		25.0		21.0		19.0	
RESOURCES TO SERVE DEMAND(GW)			32.9		41.7		49.4		59.5	
LOAD FACTOR(PERCENT)	57.3		52.8		52.5		52.5		52.5	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: SERC
SUB-REGION: FLORIDA

SHEET 5 OF 5

CONTRACT NO DACW72 78 C 0013
DATE: MARCH 1980

EXHIBIT VII-2

SERC VACAR DUKE POWER COMPANY

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 55.1
SUMMER 71.9
WINTER 69.5

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO (PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	73.7	94.2	93.5	.013	.015	.010	.016	.015	.014
1.0 - 2.0	72.7	93.2	92.5	.030	.035	.020	.049	.040	.030
2.0 - 3.0	71.7	92.2	91.5	.039	.049	.023	.073	.139	.043
3.0 - 4.0	70.7	91.2	90.5	.044	.058	.031	.086	.195	.051
4.0 - 5.0	69.7	90.2	89.5	.050	.060	.047	.107	.246	.067
5.0 - 6.0	68.7	89.2	88.5	.051	.070	.056	.111	.292	.083
6.0 - 7.0	67.7	88.2	87.5	.060	.073	.073	.168	.344	.103
7.0 - 8.0	66.7	87.2	86.5	.067	.089	.080	.263	.385	.120
8.0 - 9.0	65.7	86.2	85.5	.072	.097	.085	.336	.425	.145
9.0 - 10.0	64.7	85.2	84.5	.098	.101	.096	.470	.459	.176
10.0 - 11.0	63.7	84.2	83.5	.109	.110	.115	.560	.506	.241
11.0 - 12.0	62.7	83.2	82.5	.133	.110	.124	.627	.531	.305
12.0 - 13.0	61.7	82.2	81.5	.158	.117	.138	.664	.561	.338
13.0 - 14.0	60.7	81.2	80.5	.160	.120	.142	.693	.587	.373
14.0 - 15.0	59.7	80.2	79.5	.160	.128	.153	.716	.610	.435
15.0 - 16.0	58.7	79.2	78.5	.166	.130	.160	.736	.632	.473
16.0 - 17.0	57.7	78.2	77.5	.170	.130	.168	.771	.652	.520
17.0 - 18.0	56.7	77.2	76.5	.172	.130	.170	.799	.670	.570
18.0 - 19.0	55.7	76.2	75.5	.180	.137	.170	.823	.677	.615
19.0 - 20.0	54.7	75.2	74.5	.180	.150	.170	.867	.697	.685
20.0 - 21.0	53.7	74.2	73.5	.180	.150	.170	.882	.735	.734
21.0 - 22.0	52.7	73.2	72.5	.180	.150	.180	.904	.808	.811
22.0 - 23.0	51.7	72.2	71.5	.181	.150	.190	.918	.820	.872
23.0 - 24.0	50.7	71.2	70.5	.199	.150	.190	.977	.829	.919
24.0 - 25.0	49.7	70.2	69.5	.234	.150	.190	1.051	.848	.946
25.0 - 26.0	48.7	69.2	68.5	.240	.156	.190	1.077	.866	.973
26.0 - 27.0	47.7	68.2	67.5	.240	.170	.197	1.103	.907	1.028
27.0 - 28.0	46.7	67.2	66.5	.240	.170	.205	1.139	.939	1.079
28.0 - 29.0	45.7	66.2	65.5	.240	.170	.234	1.170	.960	1.141
29.0 - 30.0	44.7	65.2	64.5	.240	.170	.240	1.234	1.019	1.172
30.0 - 31.0	43.7	64.2	63.5	.240	.170	.240	1.325	1.044	1.184
31.0 - 32.0	42.7	63.2	62.5	.240	.179	.240	1.399	1.069	1.226
32.0 - 33.0	41.7	62.2	61.5	.240	.181	.240	1.421	1.097	1.256
33.0 - 34.0	40.7	61.2	60.5	.240	.190	.240	1.464	1.144	1.273
34.0 - 35.0	39.7	60.2	59.5	.240	.190	.240	1.517	1.185	1.291
35.0 - 36.0	38.7	59.2	58.5	.240	.200	.240	1.565	1.219	1.305
36.0 - 37.0	37.7	58.2	57.5	.240	.200	.240	1.597	1.267	1.310
37.0 - 38.0	36.7	57.2	56.5	.240	.207	.240	1.600	1.298	1.317
38.0 - 39.0	35.7	56.2	55.5	.240	.224	.240	1.600	1.341	1.321
39.0 - 40.0	34.7	55.2	54.5	.240	.240	.240	1.610	1.415	1.330
40.0 - 41.0	33.7	54.2	53.5	.240	.240	.240	1.616	1.464	1.330
41.0 - 42.0	32.7	53.2	52.5	.240	.240	.240	1.620	1.506	1.332
42.0 - 43.0	31.7	52.2	51.5	.240	.240	.240	1.627	1.517	1.348
43.0 - 44.0	30.7	51.2	50.5	.240	.240	.240	1.646	1.544	1.380
44.0 - 45.0	29.7	50.2	49.5	.240	.240	.240	1.680	1.568	1.464
45.0 - 46.0	28.7	49.2	48.5	.240	.240	.240	1.680	1.591	1.497

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: SERC
SUB-REGION: VACAR
UTILITY: DUPC

SHEET 1 OF 4

CONTRACT NO. DACW72 - 78 - C - 0013

DATE: MARCH 1980

EXHIBIT VII-3

SERC TVA TENNESSEE VALLEY AUTHORITY

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 62.4
SUMMER 69.7
WINTER 74.7

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	76.3	83.5	94.1	.018	.024	.013	.023	.028	.013
1.0 - 2.0	75.3	82.5	93.1	.025	.032	.023	.045	.057	.023
2.0 - 3.0	74.3	81.5	92.1	.030	.054	.030	.078	.144	.030
3.0 - 4.0	73.3	80.5	91.1	.036	.060	.041	.133	.257	.052
4.0 - 5.0	72.3	79.5	90.1	.044	.080	.060	.183	.354	.093
5.0 - 6.0	71.3	78.5	89.1	.075	.090	.073	.246	.422	.113
6.0 - 7.0	70.3	77.5	88.1	.094	.099	.090	.284	.471	.150
7.0 - 8.0	69.3	76.5	87.1	.100	.100	.111	.292	.502	.202
8.0 - 9.0	68.3	75.5	86.1	.127	.116	.120	.341	.550	.241
9.0 - 10.0	67.3	74.5	85.1	.140	.120	.120	.375	.614	.271
10.0 - 11.0	66.3	73.5	84.1	.169	.120	.139	.456	.651	.322
11.0 - 12.0	65.3	72.5	83.1	.186	.122	.148	.544	.763	.407
12.0 - 13.0	64.3	71.5	82.1	.201	.130	.167	.616	.816	.489
13.0 - 14.0	63.3	70.5	81.1	.229	.130	.178	.687	.865	.561
14.0 - 15.0	62.3	69.5	80.1	.232	.130	.180	.794	.910	.641
15.0 - 16.0	61.3	68.5	79.1	.240	.146	.202	.871	.956	.720
16.0 - 17.0	60.3	67.5	78.1	.240	.150	.227	.964	.990	.816
17.0 - 18.0	59.3	66.5	77.1	.240	.150	.230	1.041	1.007	.868
18.0 - 19.0	58.3	65.5	76.1	.240	.150	.230	1.116	1.045	.897
19.0 - 20.0	57.3	64.5	75.1	.240	.152	.232	1.188	1.066	.921
20.0 - 21.0	56.3	63.5	74.1	.240	.160	.240	1.273	1.109	.987
21.0 - 22.0	55.3	62.5	73.1	.240	.170	.240	1.369	1.140	1.023
22.0 - 23.0	54.3	61.5	72.1	.240	.170	.240	1.413	1.150	1.067
23.0 - 24.0	53.3	60.5	71.1	.240	.170	.240	1.444	1.192	1.117
24.0 - 25.0	52.3	59.5	70.1	.240	.175	.240	1.491	1.260	1.120
25.0 - 26.0	51.3	58.5	69.1	.240	.181	.240	1.565	1.292	1.142
26.0 - 27.0	50.3	57.5	68.1	.240	.190	.240	1.616	1.351	1.150
27.0 - 28.0	49.3	56.5	67.1	.240	.190	.240	1.620	1.415	1.151
28.0 - 29.0	48.3	55.5	66.1	.240	.207	.240	1.627	1.531	1.196
29.0 - 30.0	47.3	54.5	65.1	.240	.214	.240	1.661	1.611	1.252
30.0 - 31.0	46.3	53.5	64.1	.240	.240	.240	1.680	1.675	1.283
31.0 - 32.0	45.3	52.5	63.1	.240	.240	.240	1.680	1.680	1.318
32.0 - 33.0	44.3	51.5	62.1	.240	.240	.240	1.680	1.680	1.355
33.0 - 34.0	43.3	50.5	61.1	.240	.240	.240	1.680	1.680	1.399
34.0 - 35.0	42.3	49.5	60.1	.240	.240	.240	1.680	1.680	1.431
35.0 - 36.0	41.3	48.5	59.1	.240	.240	.240	1.680	1.680	1.473
36.0 - 37.0	40.3	47.5	58.1	.240	.240	.240	1.680	1.680	1.494
37.0 - 38.0	39.3	46.5	57.1	.240	.240	.240	1.680	1.680	1.524
38.0 - 39.0	38.3	45.5	56.1	.240	.240	.240	1.680	1.680	1.530
39.0 - 40.0	37.3	44.5	55.1	.240	.240	.240	1.680	1.680	1.539
40.0 - 41.0	36.3	43.5	54.1	.240	.240	.240	1.680	1.680	1.547
41.0 - 42.0	35.3	42.5	53.1	.240	.240	.240	1.680	1.680	1.560
42.0 - 43.0	34.3	41.5	52.1	.240	.240	.240	1.680	1.680	1.569
43.0 - 44.0	33.3	40.5	51.1	.240	.240	.240	1.680	1.680	1.596
44.0 - 45.0	32.3	39.5	50.1	.240	.240	.240	1.680	1.680	1.641
45.0 - 46.0	31.3	38.5	49.1	.240	.240	.240	1.680	1.680	1.675

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INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: SERC
SUB-REGION: TVA
UTILITY: TVA

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT VII-3

SERC SOUTH THE SOUTHERN COMPANY SYSTEM

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 50.6
SUMMER 73.6
WINTER 60.3

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO (PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	63.3	96.9	78.6	.034	.012	.014	.035	.012	.014
1.0 - 2.0	62.3	95.9	77.6	.082	.027	.037	.111	.041	.037
2.0 - 3.0	61.3	94.9	76.6	.113	.040	.060	.162	.079	.078
3.0 - 4.0	60.3	93.9	75.6	.120	.042	.070	.217	.111	.100
4.0 - 5.0	59.3	92.9	74.6	.121	.057	.080	.293	.206	.121
5.0 - 6.0	58.3	91.9	73.6	.137	.060	.084	.380	.256	.153
6.0 - 7.0	57.3	90.9	72.6	.140	.060	.101	.475	.287	.207
7.0 - 8.0	56.3	89.9	71.6	.140	.067	.110	.574	.336	.256
8.0 - 9.0	55.3	88.9	70.6	.141	.080	.119	.659	.353	.293
9.0 - 10.0	54.3	87.9	69.6	.150	.080	.120	.716	.384	.327
10.0 - 11.0	53.3	86.9	68.6	.150	.080	.134	.745	.443	.382
11.0 - 12.0	52.3	85.9	67.6	.156	.092	.160	.783	.472	.482
12.0 - 13.0	51.3	84.9	66.6	.160	.102	.169	.818	.491	.572
13.0 - 14.0	50.3	83.9	65.6	.160	.110	.170	.846	.537	.631
14.0 - 15.0	49.3	82.9	64.6	.160	.110	.170	.867	.550	.676
15.0 - 16.0	48.3	81.9	63.6	.160	.110	.170	.918	.583	.769
16.0 - 17.0	47.3	80.9	62.6	.166	.120	.176	.990	.638	.835
17.0 - 18.0	46.3	79.9	61.6	.170	.120	.180	1.072	.666	.863
18.0 - 19.0	45.3	78.9	60.6	.170	.128	.180	1.139	.711	.914
19.0 - 20.0	44.3	77.9	59.6	.173	.130	.189	1.187	.780	.958
20.0 - 21.0	43.3	76.9	58.6	.180	.130	.190	1.248	.801	1.015
21.0 - 22.0	42.3	75.9	57.6	.188	.130	.195	1.295	.840	1.051
22.0 - 23.0	41.3	74.9	56.6	.190	.132	.218	1.334	.864	1.098
23.0 - 24.0	40.3	73.9	55.6	.190	.140	.238	1.356	.880	1.171
24.0 - 25.0	39.3	72.9	54.6	.193	.140	.240	1.405	.907	1.216
25.0 - 26.0	38.3	71.9	53.6	.203	.140	.240	1.445	.940	1.241
26.0 - 27.0	37.3	70.9	52.6	.218	.145	.240	1.502	.966	1.250
27.0 - 28.0	36.3	69.9	51.6	.240	.150	.240	1.565	.985	1.251
28.0 - 29.0	35.3	68.9	50.6	.240	.152	.240	1.592	.997	1.276
29.0 - 30.0	34.3	67.9	49.6	.240	.160	.240	1.635	1.029	1.292
30.0 - 31.0	33.3	66.9	48.6	.240	.160	.240	1.665	1.042	1.305
31.0 - 32.0	32.3	65.9	47.6	.240	.160	.240	1.680	1.060	1.330
32.0 - 33.0	31.3	64.9	46.6	.240	.160	.240	1.680	1.063	1.344
33.0 - 34.0	30.3	63.9	45.6	.240	.160	.240	1.680	1.104	1.419
34.0 - 35.0	29.3	62.9	44.6	.240	.165	.240	1.680	1.125	1.450
35.0 - 36.0	28.3	61.9	43.6	.240	.170	.240	1.680	1.133	1.475
36.0 - 37.0	27.3	60.9	42.6	.240	.171	.240	1.680	1.144	1.501
37.0 - 38.0	26.3	59.9	41.6	.240	.183	.240	1.680	1.183	1.540
38.0 - 39.0	25.3	58.9	40.6	.240	.190	.240	1.680	1.218	1.550
39.0 - 40.0	24.3	57.9	39.6	.240	.190	.240	1.680	1.255	1.556
40.0 - 41.0	23.3	56.9	38.6	.240	.190	.240	1.680	1.276	1.574
41.0 - 42.0	22.3	55.9	37.6	.240	.197	.240	1.680	1.297	1.597
42.0 - 43.0	21.3	54.9	36.6	.240	.209	.240	1.680	1.339	1.631
43.0 - 44.0	20.3	53.9	35.6	.240	.217	.240	1.680	1.400	1.650
44.0 - 45.0	19.3	52.9	34.6	.240	.224	.240	1.680	1.441	1.680
45.0 - 46.0	18.3	51.9	33.6	.240	.240	.240	1.680	1.502	1.680

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO, ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: SERC
SUB-REGION: SOUTHERN
UTILITY: SOUTHERN

SHEET 3 OF 4

CONTRACT NO [illegible]72 78 C 0013

DATE MARCH 1980

EXHIBIT VII-3

SERC FLA FLORIDA POWER + LIGHT COMPANY

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 47.9
SUMMER 60.3
WINTER 48.3

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	70.6	80.3	68.3	.010	.025	.018	.010	.034	.028
1.0 - 2.0	69.6	79.3	67.3	.010	.043	.023	.019	.073	.033
2.0 - 3.0	68.6	78.3	66.3	.016	.058	.030	.026	.098	.047
3.0 - 4.0	67.6	77.3	65.3	.029	.061	.036	.049	.124	.060
4.0 - 5.0	66.6	76.3	64.3	.041	.078	.052	.079	.155	.088
5.0 - 6.0	65.6	75.3	63.3	.068	.085	.060	.150	.186	.100
6.0 - 7.0	64.6	74.3	62.3	.096	.100	.069	.194	.233	.114
7.0 - 8.0	63.6	73.3	61.3	.103	.100	.080	.210	.269	.141
8.0 - 9.0	62.6	72.3	60.3	.110	.113	.081	.223	.328	.158
9.0 - 10.0	61.6	71.3	59.3	.110	.120	.090	.230	.406	.192
10.0 - 11.0	60.6	70.3	58.3	.119	.120	.090	.245	.454	.245
11.0 - 12.0	59.6	69.3	57.3	.123	.120	.091	.253	.494	.310
12.0 - 13.0	58.6	68.3	56.3	.130	.121	.107	.273	.530	.372
13.0 - 14.0	57.6	67.3	55.3	.130	.130	.110	.304	.553	.422
14.0 - 15.0	56.6	66.3	54.3	.131	.139	.110	.323	.589	.468
15.0 - 16.0	55.6	65.3	53.3	.140	.140	.136	.370	.655	.566
16.0 - 17.0	54.6	64.3	52.3	.140	.140	.140	.420	.705	.653
17.0 - 18.0	53.6	63.3	51.3	.145	.140	.143	.452	.738	.691
18.0 - 19.0	52.6	62.3	50.3	.150	.140	.159	.503	.766	.770
19.0 - 20.0	51.6	61.3	49.3	.150	.146	.176	.567	.804	.832
20.0 - 21.0	50.6	60.3	48.3	.150	.152	.180	.628	.878	.899
21.0 - 22.0	49.6	59.3	47.3	.150	.160	.180	.732	.951	.961
22.0 - 23.0	48.6	58.3	46.3	.153	.160	.180	.904	.980	1.021
23.0 - 24.0	47.6	57.3	45.3	.164	.160	.180	.972	.998	1.085
24.0 - 25.0	46.6	56.3	44.3	.170	.160	.180	.997	1.003	1.132
25.0 - 26.0	45.6	55.3	43.3	.170	.160	.180	1.007	1.022	1.150
26.0 - 27.0	44.6	54.3	42.3	.170	.164	.180	1.045	1.070	1.164
27.0 - 28.0	43.6	53.3	41.3	.170	.180	.190	1.072	1.115	1.199
28.0 - 29.0	42.6	52.3	40.3	.170	.180	.190	1.107	1.137	1.238
29.0 - 30.0	41.6	51.3	39.3	.170	.180	.190	1.133	1.163	1.266
30.0 - 31.0	40.6	50.3	38.3	.170	.185	.190	1.148	1.186	1.301
31.0 - 32.0	39.6	49.3	37.3	.190	.190	.190	1.178	1.221	1.310
32.0 - 33.0	38.6	48.3	36.3	.190	.197	.203	1.213	1.251	1.330
33.0 - 34.0	37.6	47.3	35.3	.190	.210	.210	1.257	1.288	1.361
34.0 - 35.0	36.6	46.3	34.3	.200	.213	.230	1.303	1.325	1.417
35.0 - 36.0	35.6	45.3	33.3	.203	.234	.240	1.340	1.386	1.459
36.0 - 37.0	34.6	44.3	32.3	.222	.240	.240	1.392	1.448	1.498
37.0 - 38.0	33.6	43.3	31.3	.239	.240	.240	1.447	1.484	1.545
38.0 - 39.0	32.6	42.3	30.3	.240	.240	.240	1.485	1.518	1.594
39.0 - 40.0	31.6	41.3	29.3	.240	.240	.240	1.513	1.565	1.676
40.0 - 41.0	30.6	40.3	28.3	.240	.240	.240	1.527	1.586	1.680
41.0 - 42.0	29.6	39.3	27.3	.240	.240	.240	1.571	1.605	1.680
42.0 - 43.0	28.6	38.3	26.3	.240	.240	.240	1.612	1.644	1.680
43.0 - 44.0	27.6	37.3	25.3	.240	.240	.240	1.668	1.670	1.680
44.0 - 45.0	26.6	36.3	24.3	.240	.240	.240	1.680	1.680	1.680
45.0 - 46.0	25.6	35.3	[illegible]	.240	.240	.240	1.680	1.680	1.680

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: SERC
SUB-REGION: FLORIDA
UTILITY: FLPL

SHEET 4 OF 4

CONTRACT NO. DACW72 78 C 0013

DATE MARCH 1980

EXHIBIT VII-3

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
SOUTHWEST POWER POOL

SERVICE AREA APPROXIMATED BY BEA AREAS:

109 110 111 115 116 117 118 119 120 122
130 131 132 133 134 135 138 139 140

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	2712.	2817.	2927.	3281.
MINING	1075.	1098.	1123.	1209.
CONSTRUCTION	2959.	3451.	4025.	5449.
MANUFACTURING	10574.	12557.	14920.	20637.
TRANSPO UTILITIES	3864.	4453.	5135.	6919.
TRADE	7828.	8982.	10332.	13890.
FINANCE	2381.	2912.	3561.	5247.
SERVICES	7490.	9314.	11590.	17642.
GOVERNMENT	8104.	9781.	11810.	16988.
TOTAL EARNINGS (MILLION $)	46996.	55437.	65431.	91271.
TOTAL PERSONAL INCOME (MILLION $)	61588.	72912.	86431.	121235.
TOTAL POPULATION (THOUSANDS)	15491.	15982.	16497.	17116.
PER CAPITA INCOME ($)	3976.	4562.	5239.	7083.
PER CAPTA INCOME RELATIVE TO U. S.	.83	.84	.85	.87

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: SWPP

SUB-REGION: SWPP

SHEET 1 OF 1

CONTRACT NO DACW72 - 78 - C - 0013

DATE: MARCH 1980

EXHIBIT VIII-1

ELECTRIC POWER DEMAND
SOUTHWEST POWER POOL(SWPP)
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	16083.	.9	17124.	.6	17644.	.4	18000.	.4	18363.	.6
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	11.9	5.3	17.1	5.2	22.1	5.1	28.4	4.6	35.5	5.1
TOTAL DEMAND(THOUSAND GWH)	191.6	6.3	293.2	5.9	390.1	5.5	511.0	5.0	652.3	5.7
PEAK DEMAND(GW)	39.2	6.0	59.1	5.8	78.4	5.5	102.7	5.0	131.1	5.6
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	11.9	2.6	14.3	2.6	16.2	2.6	18.4	2.6	21.0	2.6
TOTAL DEMAND(THOUSAND GWH)	191.6	3.5	244.2	3.2	286.0	3.0	331.7	3.0	384.8	3.2
PEAK DEMAND(GW)	39.2	3.3	49.2	3.2	57.5	3.0	66.7	3.0	77.3	3.1
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	11.9	4.5	16.2	4.0	19.7	3.3	23.2	3.2	27.2	3.8
TOTAL DEMAND(THOUSAND GWH)	191.6	5.4	277.6	4.6	348.0	3.7	417.6	3.6	498.7	4.4
PEAK DEMAND(GW)	39.2	5.2	56.0	4.6	69.9	3.7	83.9	3.6	100.2	4.4
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	11.9	4.5	16.2	4.0	19.7	3.3	23.2	3.2	27.2	3.8
TOTAL DEMAND(THOUSAND GWH)	191.6	5.4	277.6	4.6	348.0	3.7	417.6	3.6	498.7	4.4
PEAK DEMAND(GW)	39.2	5.2	56.0	4.6	69.9	3.7	83.9	3.6	100.2	4.4
MARGIN(PERCENT)			19.0		18.0		18.0		18.0	
RESOURCES TO SERVE DEMAND(GW)			66.6		82.5		99.0		118.3	
LOAD FACTOR(PERCENT)	55.8		56.6		56.8		56.8		56.8	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

HARZA ENGINEERING COMPANY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: SWPP
SUB-REGION: SWPP

SHEET 1 OF 1

CONTRACT NO. DACW72 78-C-0013
DATE MARCH 1980

EXHIBIT VIII-2

SWPP GULF STATES UTILITIES COMPANY

YEAR: 1985
WEEKLY LOAD FACTOR: OFF-SEASON 60.0
SUMMER 79.7
WINTER 64.9

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	66.3	95.0	71.9	.014	.013	.010	.018	.013	.025
1.0 - 2.0	65.3	94.0	70.9	.023	.037	.038	.066	.044	.094
2.0 - 3.0	64.3	93.0	69.9	.039	.054	.057	.189	.087	.185
3.0 - 4.0	63.3	92.0	68.9	.073	.060	.074	.349	.121	.307
4.0 - 5.0	62.3	91.0	67.9	.113	.070	.089	.520	.193	.449
5.0 - 6.0	61.3	90.0	66.9	.124	.091	.123	.708	.245	.607
6.0 - 7.0	60.3	89.0	65.9	.132	.100	.141	.848	.295	.781
7.0 - 8.0	59.3	88.0	64.9	.150	.106	.164	.953	.341	.973
8.0 - 9.0	58.3	87.0	63.9	.154	.110	.170	1.062	.366	1.098
9.0 - 10.0	57.3	86.0	62.9	.160	.119	.174	1.137	.426	1.174
10.0 - 11.0	56.3	85.0	61.9	.160	.120	.208	1.196	.471	1.253
11.0 - 12.0	55.3	84.0	60.9	.163	.120	.229	1.268	.569	1.297
12.0 - 13.0	54.3	83.0	59.9	.184	.120	.230	1.378	.668	1.326
13.0 - 14.0	53.3	82.0	58.9	.194	.132	.239	1.499	.738	1.354
14.0 - 15.0	52.3	81.0	57.9	.229	.140	.240	1.630	.820	1.385
15.0 - 16.0	51.3	80.0	56.9	.240	.140	.240	1.680	.862	1.427
16.0 - 17.0	50.3	79.0	55.9	.240	.140	.240	1.680	.901	1.545
17.0 - 18.0	49.3	78.0	54.9	.240	.143	.240	1.680	.945	1.633
18.0 - 19.0	48.3	77.0	53.9	.240	.150	.240	1.680	.967	1.680
19.0 - 20.0	47.3	76.0	52.9	.240	.159	.240	1.680	1.011	1.680
20.0 - 21.0	46.3	75.0	51.9	.240	.160	.240	1.680	1.044	1.680
21.0 - 22.0	45.3	74.0	50.9	.240	.160	.240	1.680	1.085	1.680
22.0 - 23.0	44.3	73.0	49.9	.240	.168	.240	1.680	1.121	1.680
23.0 - 24.0	43.3	72.0	48.9	.240	.177	.240	1.680	1.172	1.680
24.0 - 25.0	42.3	71.0	47.9	.240	.180	.240	1.680	1.218	1.680
25.0 - 26.0	41.3	70.0	46.9	.240	.187	.240	1.680	1.256	1.680
26.0 - 27.0	40.3	69.0	45.9	.240	.197	.240	1.680	1.320	1.680
27.0 - 28.0	39.3	68.0	44.9	.240	.220	.240	1.680	1.433	1.680
28.0 - 29.0	38.3	67.0	43.9	.240	.240	.240	1.680	1.555	1.680
29.0 - 30.0	37.3	66.0	42.9	.240	.240	.240	1.680	1.627	1.680
30.0 - 31.0	36.3	65.0	41.9	.240	.240	.240	1.680	1.672	1.680
31.0 - 32.0	35.3	64.0	40.9	.240	.240	.240	1.680	1.680	1.680
32.0 - 33.0	34.3	63.0	39.9	.240	.240	.240	1.680	1.680	1.680

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: SWPP
SUB-REGION: SWPP
UTILITY: GUSU

SHEET 1 OF 4

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT VIII-3

SWPP OKLAHOMA GAS AND ELECTRIC COMPANY

YEAR: 1985
WEEKLY LOAD FACTOR: OFF-SEASON 41.1
SUMMER 67.1
WINTER 53.0

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	50.8	95.6	65.9	.019	.019	.025	.027	.027	.025
1.0 - 2.0	49.8	94.6	64.9	.038	.030	.036	.078	.056	.036
2.0 - 3.0	48.8	93.6	63.9	.052	.049	.050	.135	.105	.074
3.0 - 4.0	47.8	92.6	62.9	.074	.053	.065	.262	.118	.148
4.0 - 5.0	46.8	91.6	61.9	.090	.060	.081	.412	.156	.235
5.0 - 6.0	45.8	90.6	60.9	.114	.061	.098	.577	.164	.312
6.0 - 7.0	44.8	89.6	59.9	.153	.073	.117	.699	.183	.360
7.0 - 8.0	43.8	88.6	58.9	.160	.080	.139	.734	.200	.432
8.0 - 9.0	42.8	87.6	57.9	.160	.085	.155	.772	.232	.525
9.0 - 10.0	41.8	86.6	56.9	.165	.091	.160	.789	.245	.642
10.0 - 11.0	40.8	85.6	55.9	.170	.100	.167	.859	.272	.733
11.0 - 12.0	39.8	84.6	54.9	.176	.100	.170	.961	.289	.831
12.0 - 13.0	38.8	83.6	53.9	.180	.100	.170	1.008	.324	.917
13.0 - 14.0	37.8	82.6	52.9	.186	.107	.174	1.028	.343	.954
14.0 - 15.0	36.8	81.6	51.9	.224	.116	.186	1.105	.373	.996
15.0 - 16.0	35.8	80.6	50.9	.240	.120	.190	1.194	.390	1.018
16.0 - 17.0	34.8	79.6	49.9	.240	.120	.201	1.255	.404	1.065
17.0 - 18.0	33.8	78.6	48.9	.240	.130	.229	1.305	.442	1.114
18.0 - 19.0	32.8	77.6	47.9	.240	.130	.240	1.361	.450	1.166
19.0 - 20.0	31.8	76.6	46.9	.240	.130	.240	1.410	.457	1.230
20.0 - 21.0	30.8	75.6	45.9	.240	.133	.240	1.468	.489	1.329
21.0 - 22.0	29.8	74.6	44.9	.240	.140	.240	1.585	.558	1.362
22.0 - 23.0	28.8	73.6	43.9	.240	.140	.240	1.641	.600	1.376
23.0 - 24.0	27.8	72.6	42.9	.240	.140	.240	1.672	.608	1.386
24.0 - 25.0	26.8	71.6	41.9	.240	.140	.240	1.680	.640	1.438
25.0 - 26.0	25.8	70.6	40.9	.240	.140	.240	1.680	.660	1.490
26.0 - 27.0	24.8	69.6	39.9	.240	.140	.240	1.680	.681	1.516
27.0 - 28.0	23.8	68.6	38.9	.240	.141	.240	1.680	.704	1.531
28.0 - 29.0	22.8	67.6	37.9	.240	.155	.240	1.680	.764	1.542
29.0 - 30.0	21.8	66.6	36.9	.240	.160	.240	1.680	.823	1.555
30.0 - 31.0	20.8	65.6	35.9	.240	.160	.240	1.680	.859	1.567
31.0 - 32.0	19.8	64.6	34.9	.240	.160	.240	1.680	.882	1.598
32.0 - 33.0	18.8	63.6	33.9	.240	.160	.240	1.680	.905	1.627
33.0 - 34.0	17.8	62.6	32.9	.240	.160	.240	1.680	.927	1.640
34.0 - 35.0	16.8	61.6	31.9	.240	.160	.240	1.680	.966	1.677
35.0 - 36.0	15.8	60.6	30.9	.240	.160	.240	1.680	1.010	1.680
36.0 - 37.0	14.8	59.6	29.9	.240	.160	.240	1.680	1.024	1.680
37.0 - 38.0	13.8	58.6	28.9	.240	.172	.240	1.680	1.065	1.680
38.0 - 39.0	12.8	57.6	27.9	.240	.180	.240	1.680	1.100	1.680
39.0 - 40.0	11.8	56.6	26.9	.240	.180	.240	1.680	1.130	1.680
40.0 - 41.0	10.8	55.6	25.9	.240	.181	.240	1.680	1.156	1.680
41.0 - 42.0	9.8	54.6	24.9	.240	.190	.240	1.680	1.190	1.680
42.0 - 43.0	8.8	53.6	23.9	.240	.190	.240	1.680	1.220	1.680
43.0 - 44.0	7.8	52.6	22.9	.240	.197	.240	1.680	1.263	1.680
44.0 - 45.0	6.8	51.6	21.9	.240	.210	.240	1.680	1.325	1.680
45.0 - 46.0	5.8	50.6	20.9	.240	.219	.240	1.680	1.395	1.680

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO, ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: SWPP
SUB-REGION: SWPP
UTILITY: OKGE

SHEET 2 OF 4

CONTRACT NO. DACW72 - 78 - C - 0013
DATE MARCH 1980

EXHIBIT VIII-3

SWPP SOUTHWESTERN ELECTRIC POWER COMPANY

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 40.5
SUMMER 69.4
WINTER 48.7

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	49.8	94.8	61.4	.010	.020	.022	.023	.020	.024
1.0 - 2.0	48.8	93.8	60.4	.033	.040	.044	.110	.050	.055
2.0 - 3.0	47.8	92.8	59.4	.077	.044	.076	.232	.096	.112
3.0 - 4.0	46.8	91.8	58.4	.114	.050	.080	.365	.136	.157
4.0 - 5.0	45.8	90.8	57.4	.128	.056	.103	.474	.153	.232
5.0 - 6.0	44.8	89.8	56.4	.140	.060	.136	.559	.172	.300
6.0 - 7.0	43.8	88.8	55.4	.140	.066	.145	.665	.208	.344
7.0 - 8.0	42.8	87.8	54.4	.145	.076	.152	.736	.240	.425
8.0 - 9.0	41.8	86.8	53.4	.150	.080	.160	.797	.272	.532
9.0 - 10.0	40.8	85.8	52.4	.150	.087	.160	.862	.322	.616
10.0 - 11.0	39.8	84.8	51.4	.150	.095	.160	.919	.343	.712
11.0 - 12.0	38.8	83.8	50.4	.161	.100	.160	.963	.377	.799
12.0 - 13.0	37.8	82.8	49.4	.170	.100	.160	1.001	.416	.882
13.0 - 14.0	36.8	81.8	48.4	.170	.108	.167	1.057	.447	.935
14.0 - 15.0	35.8	80.8	47.4	.170	.110	.180	1.139	.463	.997
15.0 - 16.0	34.8	79.8	46.4	.171	.120	.180	1.207	.501	1.029
16.0 - 17.0	33.8	78.8	45.4	.181	.120	.185	1.275	.547	1.054
17.0 - 18.0	32.8	77.8	44.4	.190	.120	.211	1.337	.550	1.115
18.0 - 19.0	31.8	76.8	43.4	.209	.120	.236	1.381	.563	1.177
19.0 - 20.0	30.8	75.8	42.4	.239	.120	.240	1.450	.624	1.235
20.0 - 21.0	29.8	74.8	41.4	.240	.134	.240	1.510	.671	1.278
21.0 - 22.0	28.8	73.8	40.4	.240	.140	.240	1.580	.696	1.319
22.0 - 23.0	27.8	72.8	39.4	.240	.140	.240	1.672	.724	1.370
23.0 - 24.0	26.8	71.8	38.4	.240	.140	.240	1.680	.764	1.464
24.0 - 25.0	25.8	70.8	37.4	.240	.140	.240	1.680	.790	1.518
25.0 - 26.0	24.8	69.8	36.4	.240	.140	.240	1.680	.818	1.524
26.0 - 27.0	23.8	68.8	35.4	.240	.142	.240	1.680	.848	1.540
27.0 - 28.0	22.8	67.8	34.4	.240	.150	.240	1.680	.878	1.546
28.0 - 29.0	21.8	66.8	33.4	.240	.150	.240	1.680	.919	1.563
29.0 - 30.0	20.8	65.8	32.4	.240	.153	.240	1.680	.968	1.599
30.0 - 31.0	19.8	64.8	31.4	.240	.160	.240	1.680	.988	1.643
31.0 - 32.0	18.8	63.8	30.4	.240	.160	.240	1.680	.996	1.655
32.0 - 33.0	17.8	62.8	29.4	.240	.160	.240	1.680	1.010	1.680
33.0 - 34.0	16.8	61.8	28.4	.240	.161	.240	1.680	1.030	1.680
34.0 - 35.0	15.8	60.8	27.4	.240	.170	.240	1.680	1.056	1.680
35.0 - 36.0	14.8	59.8	26.4	.240	.174	.240	1.680	1.074	1.680
36.0 - 37.0	13.8	58.8	25.4	.240	.180	.240	1.680	1.118	1.680
37.0 - 38.0	12.8	57.8	24.4	.240	.185	.240	1.680	1.138	1.680
38.0 - 39.0	11.8	56.8	23.4	.240	.190	.240	1.680	1.178	1.680
39.0 - 40.0	10.8	55.8	22.4	.240	.190	.240	1.680	1.217	1.680
40.0 - 41.0	9.8	54.8	21.4	.240	.195	.240	1.680	1.231	1.680
41.0 - 42.0	8.8	53.8	20.4	.240	.202	.240	1.680	1.259	1.680
42.0 - 43.0	7.8	52.8	19.4	.240	.215	.240	1.680	1.310	1.680
43.0 - 44.0	6.8	51.8	18.4	.240	.231	.240	1.680	1.362	1.680
44.0 - 45.0	5.8	50.8	17.4	.240	.240	.240	1.680	1.426	1.680
45.0 - 46.0	4.8	49.8	16.4	.240	.240	.240	1.680	1.476	1.680

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: SWPP
SUB-REGION: SWPP
UTILITY: SOEP

SHEET 3 OF 4

CONTRACT NO. DACW72 78 C 0013
DATE MARCH 1980

EXHIBIT VIII-3

SWPP KANSAS CITY POWER AND LIGHT COMPANY

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 41.0
SUMMER 63.9
WINTER 49.3

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
***********	********	********	********	**********	******	******	**********	******	******
.0 - 1.0	53.0	99.0	62.4	.010	.018	.013	.012	.018	.019
1.0 - 2.0	52.0	98.0	61.4	.022	.026	.020	.053	.026	.050
2.0 - 3.0	51.0	97.0	60.4	.036	.030	.029	.134	.030	.085
3.0 - 4.0	50.0	96.0	59.4	.079	.030	.078	.259	.030	.205
4.0 - 5.0	49.0	95.0	58.4	.107	.047	.099	.354	.052	.289
5.0 - 6.0	48.0	94.0	57.4	.128	.054	.110	.428	.064	.370
6.0 - 7.0	47.0	93.0	56.4	.140	.060	.129	.481	.079	.500
7.0 - 8.0	46.0	92.0	55.4	.140	.060	.140	.545	.105	.601
8.0 - 9.0	45.0	91.0	54.4	.146	.070	.140	.603	.123	.668
9.0 - 10.0	44.0	90.0	53.4	.160	.075	.140	.655	.136	.710
10.0 - 11.0	43.0	89.0	52.4	.160	.080	.155	.698	.161	.736
11.0 - 12.0	42.0	88.0	51.4	.160	.080	.160	.730	.178	.760
12.0 - 13.0	41.0	87.0	50.4	.160	.081	.160	.765	.190	.790
13.0 - 14.0	40.0	86.0	49.4	.160	.090	.160	.837	.215	.833
14.0 - 15.0	39.0	85.0	48.4	.161	.095	.160	.904	.242	.855
15.0 - 16.0	38.0	84.0	47.4	.170	.100	.160	.979	.264	.900
16.0 - 17.0	37.0	83.0	46.4	.179	.110	.170	1.041	.290	.943
17.0 - 18.0	36.0	82.0	45.4	.180	.110	.180	1.103	.306	1.014
18.0 - 19.0	35.0	81.0	44.4	.181	.110	.180	1.179	.327	1.057
19.0 - 20.0	34.0	80.0	43.4	.190	.110	.180	1.254	.337	1.143
20.0 - 21.0	33.0	79.0	42.4	.190	.110	.180	1.299	.350	1.220
21.0 - 22.0	32.0	78.0	41.4	.202	.117	.180	1.367	.378	1.281
22.0 - 23.0	31.0	77.0	40.4	.224	.130	.184	1.461	.413	1.331
23.0 - 24.0	30.0	76.0	39.4	.238	.130	.192	1.515	.420	1.410
24.0 - 25.0	29.0	75.0	38.4	.240	.130	.215	1.580	.423	1.472
25.0 - 26.0	28.0	74.0	37.4	.240	.130	.223	1.636	.448	1.503
26.0 - 27.0	27.0	73.0	36.4	.240	.130	.238	1.668	.450	1.521
27.0 - 28.0	26.0	72.0	35.4	.240	.130	.240	1.680	.478	1.547
28.0 - 29.0	25.0	71.0	34.4	.240	.140	.240	1.680	.521	1.572
29.0 - 30.0	24.0	70.0	33.4	.240	.143	.240	1.680	.542	1.590
30.0 - 31.0	23.0	69.0	32.4	.240	.150	.240	1.680	.565	1.610
31.0 - 32.0	22.0	68.0	31.4	.240	.150	.240	1.680	.577	1.622
32.0 - 33.0	21.0	67.0	30.4	.240	.150	.240	1.680	.595	1.643
33.0 - 34.0	20.0	66.0	29.4	.240	.150	.240	1.680	.613	1.674
34.0 - 35.0	19.0	65.0	28.4	.240	.154	.240	1.680	.652	1.680
35.0 - 36.0	18.0	64.0	27.4	.240	.160	.240	1.680	.681	1.680
36.0 - 37.0	17.0	63.0	26.4	.240	.163	.240	1.680	.718	1.680
37.0 - 38.0	16.0	62.0	25.4	.240	.170	.240	1.680	.776	1.680
38.0 - 39.0	15.0	61.0	24.4	.240	.173	.240	1.680	.795	1.680
39.0 - 40.0	14.0	60.0	23.4	.240	.180	.240	1.680	.841	1.680
40.0 - 41.0	13.0	59.0	22.4	.240	.180	.240	1.680	.925	1.680
41.0 - 42.0	12.0	58.0	21.4	.240	.180	.240	1.680	.980	1.680
42.0 - 43.0	11.0	57.0	20.4	.240	.185	.240	1.680	1.016	1.680
43.0 - 44.0	10.0	56.0	19.4	.240	.190	.240	1.680	1.030	1.680
44.0 - 45.0	9.0	55.0	18.4	.240	.190	.240	1.680	1.065	1.680
45.0 - 46.0	8.0	54.0	17.4	.240	.199	.240	1.680	1.131	1.680

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO, ILLINOIS

DEPARTMENT OF THE ARMY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: SWPP
SUB-REGION: SWPP
UTILITY: KACP

SHEET 4 OF 4

CONTRACT NO. DACW72 78 C 0013
DATE: MARCH 1980

EXHIBIT VIII-3

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
ELECTRIC RELIABILITY COUNCIL OF TEXAS

SERVICE AREA APPROXIMATED BY BEA AREAS:
121 123 124 125 126 127 128 129 141 142
143 144

SECTOR EARNINGS (MILLION $)	YEAR 1980	1985	1990	2000
AGRICULTURE	1291.	1333.	1378.	1536.
MINING	935.	961.	989.	1070.
CONSTRUCTION	2385.	2832.	3363.	4601.
MANUFACTURING	7141.	8518.	10165.	14096.
TRANSPO UTILITIES	2633.	3147.	3764.	5323.
TRADE	6647.	7800.	9158.	12659.
FINANCE	2319.	2898.	3623.	5494.
SERVICES	6412.	8134.	10324.	16152.
GOVERNMENT	6954.	8424.	10219.	14811.
TOTAL EARNINGS (MILLION $)	36723.	44095.	52988.	75806.
TOTAL PERSONAL INCOME (MILLION $)	46503.	56120.	67786.	97759.
TOTAL POPULATION (THOUSANDS)	10505.	11119.	11781.	12755.
PER CAPITA INCOME ($)	4427.	5047.	5754.	7664.
PER CAPTA INCOME RELATIVE TO U. S.	.93	.93	.93	.94

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: ERCOT
SUB-REGION: ERCOT

SHEET 1 OF 1

CONTRACT NO. DACW72 – 78 – C – 0013
DATE MARCH 1980

EXHIBIT IX–1

ELECTRIC POWER DEMAND
ELECTRIC RELIABILITY COUNCIL OF TEXAS(ERCOT)
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	11283.	1.5	12523.	1.2	13292.	.8	13832.	.8	14395.	1.1
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	13.1	3.4	16.5	3.6	19.6	3.8	23.7	3.7	28.5	3.6
TOTAL DEMAND(THOUSAND GWH)	147.4	4.9	206.2	4.8	261.2	4.7	328.0	4.6	409.7	4.8
PEAK DEMAND(GW)	28.6	5.4	41.3	4.9	52.4	4.7	65.8	4.6	82.2	4.9
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	13.1	2.6	15.6	2.6	17.8	2.6	20.2	2.6	23.0	2.6
TOTAL DEMAND(THOUSAND GWH)	147.4	4.1	195.8	3.8	236.3	3.4	279.6	3.4	330.8	3.7
PEAK DEMAND(GW)	28.6	4.6	39.2	3.9	47.4	3.4	56.1	3.4	66.4	3.9
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	13.1	4.5	17.8	4.0	21.6	3.3	25.4	3.2	29.8	3.8
TOTAL DEMAND(THOUSAND GWH)	147.4	6.1	222.6	5.2	287.5	4.1	351.9	4.0	428.7	5.0
PEAK DEMAND(GW)	28.6	6.6	44.6	5.3	57.7	4.1	70.6	4.0	86.0	5.1
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	13.1	3.4	16.5	3.6	19.6	3.8	23.7	3.7	28.5	3.6
TOTAL DEMAND(THOUSAND GWH)	147.4	4.9	206.2	4.8	261.2	4.7	328.0	4.6	409.7	4.8
PEAK DEMAND(GW)	28.6	5.4	41.3	4.9	52.4	4.7	65.8	4.6	82.2	4.9
MARGIN(PERCENT)			25.0		18.0		17.0		17.0	
RESOURCES TO SERVE DEMAND(GW)			51.6		61.8		77.0		96.2	
LOAD FACTOR(PERCENT)	58.8		57.0		56.9		56.9		56.9	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO, ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: ERCOT
SUB-REGION: ERCOT

SHEET 1 OF 1

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT IX-2

ERCOT HOUSTON LIGHTING AND POWER COMPANY

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 53.9
SUMMER 79.0
WINTER 58.3

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	63.1	98.7	66.7	.026	.010	.014	.026	.010	.027
1.0 - 2.0	62.1	97.7	65.7	.049	.035	.027	.051	.035	.098
2.0 - 3.0	61.1	96.7	64.7	.068	.047	.035	.100	.050	.159
3.0 - 4.0	60.1	95.7	63.7	.087	.056	.063	.170	.079	.264
4.0 - 5.0	59.1	94.7	62.7	.107	.063	.085	.271	.123	.366
5.0 - 6.0	58.1	93.7	61.7	.110	.073	.113	.404	.173	.525
6.0 - 7.0	57.1	92.7	60.7	.124	.080	.120	.583	.207	.667
7.0 - 8.0	56.1	91.7	59.7	.130	.082	.130	.705	.234	.840
8.0 - 9.0	55.1	90.7	58.7	.140	.090	.133	.823	.278	.925
9.0 - 10.0	54.1	89.7	57.7	.145	.099	.150	.903	.317	1.008
10.0 - 11.0	53.1	88.7	56.7	.160	.110	.150	.964	.353	1.024
11.0 - 12.0	52.1	87.7	55.7	.160	.110	.160	1.018	.414	1.065
12.0 - 13.0	51.1	86.7	54.7	.160	.110	.160	1.084	.494	1.150
13.0 - 14.0	50.1	85.7	53.7	.160	.118	.160	1.125	.565	1.189
14.0 - 15.0	49.1	84.7	52.7	.169	.127	.168	1.172	.613	1.269
15.0 - 16.0	48.1	83.7	51.7	.175	.130	.180	1.221	.663	1.339
16.0 - 17.0	47.1	82.7	50.7	.192	.130	.180	1.290	.706	1.398
17.0 - 18.0	46.1	81.7	49.7	.205	.130	.184	1.432	.751	1.442
18.0 - 19.0	45.1	80.7	48.7	.230	.136	.200	1.514	.808	1.525
19.0 - 20.0	44.1	79.7	47.7	.240	.141	.215	1.639	.846	1.614
20.0 - 21.0	43.1	78.7	46.7	.240	.150	.240	1.680	.886	1.676
21.0 - 22.0	42.1	77.7	45.7	.240	.150	.240	1.680	.909	1.680
22.0 - 23.0	41.1	76.7	44.7	.240	.150	.240	1.680	.926	1.680
23.0 - 24.0	40.1	75.7	43.7	.240	.155	.240	1.680	.974	1.680
24.0 - 25.0	39.1	74.7	42.7	.240	.160	.240	1.680	1.011	1.680
25.0 - 26.0	38.1	73.7	41.7	.240	.160	.240	1.680	1.027	1.680
26.0 - 27.0	37.1	72.7	40.7	.240	.160	.240	1.680	1.053	1.680
27.0 - 28.0	36.1	71.7	39.7	.240	.160	.240	1.680	1.099	1.680
28.0 - 29.0	35.1	70.7	38.7	.240	.164	.240	1.680	1.135	1.680
29.0 - 30.0	34.1	69.7	37.7	.240	.174	.240	1.680	1.179	1.680
30.0 - 31.0	33.1	68.7	36.7	.240	.180	.240	1.680	1.217	1.680
31.0 - 32.0	32.1	67.7	35.7	.240	.185	.240	1.680	1.263	1.680
32.0 - 33.0	31.1	66.7	34.7	.240	.190	.240	1.680	1.302	1.680
33.0 - 34.0	30.1	65.7	33.7	.240	.207	.240	1.680	1.370	1.680
34.0 - 35.0	29.1	64.7	32.7	.240	.210	.240	1.680	1.439	1.680
35.0 - 36.0	28.1	63.7	31.7	.240	.223	.240	1.680	1.517	1.680
36.0 - 37.0	27.1	62.7	30.7	.240	.239	.240	1.680	1.579	1.680
37.0 - 38.0	26.1	61.7	29.7	.240	.240	.240	1.680	1.621	1.680
38.0 - 39.0	25.1	60.7	28.7	.240	.240	.240	1.680	1.643	1.680
39.0 - 40.0	24.1	59.7	27.7	.240	.240	.240	1.680	1.654	1.680
40.0 - 41.0	23.1	58.7	26.7	.240	.240	.240	1.680	1.672	1.680
41.0 - 42.0	22.1	57.7	25.7	.240	.240	.240	1.680	1.680	1.680
42.0 - 43.0	21.1	56.7	24.7	.240	.240	.240	1.680	1.680	1.680

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: ERCOT
SUB-REGION: ERCOT
UTILITY: HOLP

SHEET 1 OF 1

CONTRACT NO. DACW72-78-C-0013
DATE: MARCH 1980

EXHIBIT IX-3

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
WESTERN SYSTEMS
COORDINATING COUNCIL (WSCC)

SERVICE AREA APPROXIMATED BY BEA AREAS:

94	95	145	146	147	148	149	150	151	152
153	154	155	156	157	158	159	160	161	162
163	164	165	166	167	168	169	170	171	

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	4255.	4430.	4632.	5219.
MINING	1339.	1428.	1525.	1761.
CONSTRUCTION	8959.	10516.	12346.	16902.
MANUFACTURING	29405.	33953.	39220.	52249.
TRANSPO UTILITIES	10682.	12644.	14975.	20985.
TRADE	24163.	27933.	32301.	43868.
FINANCE	8636.	10629.	13086.	19477.
SERVICES	28449.	35317.	43793.	66491.
GOVERNMENT	30869.	37189.	44786.	64351.
TOTAL EARNINGS (MILLION $)	146789.	174152.	206676.	291313.
TOTAL PERSONAL INCOME (MILLION $)	188236.	224446.	267701.	380054.
TOTAL POPULATION (THOUSANDS)	37884.	39938.	42160.	45424.
PER CAPITA INCOME ($)	4969.	5620.	6350.	8367.
PER CAPTA INCOME RELATIVE TO U. S.	1.04	1.04	1.03	1.02

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
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CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: WSCC
SUB-REGION: WSCC

SHEET 1 OF 6

CONTRACT NO DACW72 - 78 - C - 0013
DATE MARCH 1980

EXHIBIT X-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
WESTERN SYSTEMS COORDINATING COUNCIL
NORTHWEST POWER POOL AREA

SERVICE AREA APPROXIMATED BY BEA AREAS:
94 95 151 152 153 154 155 156 157 158
159

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	1232.	1274.	1318.	1471.
MINING	271.	289.	308.	357.
CONSTRUCTION	1893.	2194.	2544.	3413.
MANUFACTURING	6064.	6979.	8034.	10541.
TRANSPO UTILITIES	2189.	2537.	2942.	3982.
TRADE	5074.	5808.	6650.	8912.
FINANCE	1600.	1950.	2378.	3493.
SERVICES	5051.	6297.	7787.	11780.
GOVERNMENT	6401.	7657.	9164.	13073.
TOTAL EARNINGS (MILLION $)	29778.	34991.	41129.	57025.
TOTAL PERSONAL INCOME (MILLION $)	38359.	45276.	53461.	74642.
TOTAL POPULATION (THOUSANDS)	8423.	8734.	9060.	9506.
PER CAPITA INCOME ($)	4554.	5184.	5901.	7852.
PER CAPTA INCOME RELATIVE TO U. S.	.95	.95	.96	.96

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: WSCC

SUB-REGION: NWPP

SHEET 2 OF 6

CONTRACT NO. DACW72 - 78 - C - 0013

DATE: MARCH 1980

EXHIBIT X-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
WESTERN SYSTEMS COORDINATING COUNCIL
ROCKY MOUNTIAN POWER AREA

SERVICE AREA APPROXIMATED BY BEA AREAS:
147 148 149 150

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	414.	439.	466.	536.
MINING	265.	287.	310.	361.
CONSTRUCTION	777.	904.	1053.	1425.
MANUFACTURING	1653.	1893.	2167.	2929.
TRANSPO UTILITIES	821.	971.	1149.	1609.
TRADE	1902.	2225.	2605.	3587.
FINANCE	609.	757.	941.	1416.
SERVICES	1848.	2315.	2900.	4460.
GOVERNMENT	2343.	2826.	3408.	4904.
TOTAL EARNINGS (MILLION $)	10635.	12629.	15001.	21227.
TOTAL PERSONAL INCOME (MILLION $)	13417.	16025.	19145.	27314.
TOTAL POPULATION (THOUSANDS)	2889.	3038.	3197.	3442.
PER CAPITA INCOME ($)	4645.	5275.	5989.	7936.
PER CAPTA INCOME RELATIVE TO U. S.	.97	.97	.97	.97

NOTE; SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
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CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: WSCC

SUB-REGION: RMPA

SHEET 3 OF 6

CONTRACT NO DACW72 - 78 - C - 0013

DATE: MARCH 1980

EXHIBIT X-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
WESTERN SYSTEMS COORDINATING COUNCIL
ARIZONA-NEW MEXICO POWER AREA

SERVICE AREA APPROXIMATED BY BEA AREAS:
145 146 162 163

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	415.	435.	455.	514.
MINING	427.	467.	510.	607.
CONSTRUCTION	870.	1037.	1237.	1712.
MANUFACTURING	1628.	1978.	2404.	3398.
TRANSPO UTILITIES	748.	905.	1096.	1579.
TRADE	1830.	2166.	2563.	3566.
FINANCE	709.	899.	1140.	1756.
SERVICES	2183.	2772.	3524.	5481.
GOVERNMENT	2790.	3403.	4155.	6048.
TOTAL EARNINGS (MILLION $)	11601.	14074.	17085.	24664.
TOTAL PERSONAL INCOME (MILLION $)	14590.	17810.	21753.	31687.
TOTAL POPULATION (THOUSANDS)	3513.	3785.	4082.	4503.
PER CAPITA INCOME ($)	4154.	4706.	5329.	7037.
PER CAPTA INCOME RELATIVE TO U. S.	.87	.87	.86	.86

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: WSCC

SUB-REGION: ARZ-NM

SHEET 4 OF 6

CONTRACT NO. DACW72-78-C-0013

DATE: MARCH 1980

EXHIBIT X-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
WESTERN SYSTEMS COORDINATING COUNCIL
SOUTHERN CALIFORNIA-NEVADA POWER AREA

SERVICE AREA APPROXIMATED BY BEA AREAS:
161 164 165 166

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	1334.	1394.	1457.	1644.
MINING	292.	296.	300.	323.
CONSTRUCTION	3327.	3911.	4597.	6323.
MANUFACTURING	13945.	15971.	18296.	24131.
TRANSPO UTILITIES	3944.	4730.	5673.	8083.
TRADE	9906.	11405.	13132.	17761.
FINANCE	3617.	4455.	5487.	8172.
SERVICES	12819.	15711.	19260.	28852.
GOVERNMENT	11225.	13537.	16324.	23467.
TOTAL EARNINGS (MILLION $)	60411.	71455.	84529.	118757.
TOTAL PERSONAL INCOME (MILLION $)	77131.	91725.	109095.	154452.
TOTAL POPULATION (THOUSANDS)	14753.	15568.	16432.	17769.
PER CAPITA INCOME ($)	5228.	5892.	6639.	8692.
PER CAPTA INCOME RELATIVE TO U. S.	1.09	1.09	1.08	1.06

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
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CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS
REGION: WSCC
SUB-REGION: SO CAL-NEV

SHEET 5 OF 6

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT X-1

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
WESTERN SYSTEMS COORDINATING COUNCIL
NORTHERN CALIFORNIA-NEVADA POWER AREA

SERVICE AREA APPROXIMATED BY BEA AREAS:
160 167 168 169 170 171

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	861.	897.	936.	1054.
MINING	82.	89.	96.	113.
CONSTRUCTION	2093.	2470.	2915.	4029.
MANUFACTURING	6115.	7132.	8319.	11250.
TRANSPO UTILITIES	2980.	3501.	4114.	5732.
TRADE	5450.	6329.	7351.	10042.
FINANCE	2102.	2569.	3140.	4640.
SERVICES	6548.	8221.	10322.	15918.
GOVERNMENT	8130.	9767.	11735.	16858.
TOTAL EARNINGS (MILLION $)	34364.	41003.	48932.	69639.
TOTAL PERSONAL INCOME (MILLION $)	44739.	53609.	64246.	91958.
TOTAL POPULATION (THOUSANDS)	8306.	8813.	9389.	10204.
PER CAPITA INCOME ($)	5386.	6083.	6843.	9012.
PER CAPTA INCOME RELATIVE TO U. S.	1.13	1.12	1.11	1.10

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: WSCC

SUB-REGION: NO CAL-NEV

SHEET 6 OF 6

CONTRACT NO. DACW72-78-C-0013

DATE: MARCH 1980

EXHIBIT X-1

ELECTRIC POWER DEMAND
WESTERN SYSTEMS COORDINATING COUNCIL(WSCC)
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	39506.	1.4	43658.	1.1	46084.	.7	47829.	.7	49644.	1.0
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	10.4	3.5	13.2	2.9	15.3	3.1	17.8	3.0	20.7	3.2
TOTAL DEMAND(THOUSAND GWH)	410.1	5.0	578.0	4.0	704.9	3.9	851.5	3.8	1026.3	4.3
PEAK DEMAND(GW)	68.7	5.3	98.4	3.8	118.3	3.9	142.9	3.9	173.4	4.3
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	10.4	2.6	12.4	2.6	14.0	2.6	15.9	2.6	18.1	2.6
TOTAL DEMAND(THOUSAND GWH)	410.1	4.0	541.4	3.6	647.4	3.3	762.1	3.3	897.1	3.6
PEAK DEMAND(GW)	68.7	4.3	92.2	3.3	108.7	3.3	127.9	3.5	151.6	3.7
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	10.4	4.5	14.1	4.0	17.1	3.3	20.1	3.2	23.4	3.8
TOTAL DEMAND(THOUSAND GWH)	410.1	6.0	615.7	5.1	787.8	4.0	959.4	3.9	1162.8	4.9
PEAK DEMAND(GW)	68.7	6.2	104.8	4.8	132.2	4.0	161.0	4.1	196.5	4.9
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	10.4	3.6	13.3	3.2	15.5	3.0	18.0	3.0	20.8	3.2
TOTAL DEMAND(THOUSAND GWH)	410.1	5.1	579.0	4.3	714.9	3.8	859.4	3.7	1033.1	4.3
PEAK DEMAND(GW)	68.7	5.3	98.6	4.0	120.0	3.8	144.2	3.9	174.6	4.3
MARGIN(PERCENT)			37.2		39.2		39.2		38.1	
RESOURCES TO SERVE DEMAND(GW)			135.3		167.0		200.7		241.1	
LOAD FACTOR(PERCENT)	68.1		67.1		68.0		68.0		67.6	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO, ILLINOIS

DEPARTMENT OF THE ARMY
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CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: WSCC
SUB-REGION: WSCC

SHEET 1 OF 6

CONTRACT NO. DACW72 - 78 - C - 0013
DATE MARCH 1980

EXHIBIT X – 2

ELECTRIC POWER DEMAND
NORTHWEST POWER POOL AREA
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	9220.	1.2	10023.	.7	10379.	.5	10641.	.5	10909.	.8
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	17.9	4.3	24.0	3.6	28.7	3.4	33.8	3.4	39.9	3.7
TOTAL DEMAND(THOUSAND GWH)	165.3	5.5	240.7	4.3	297.7	3.9	359.9	3.9	435.7	4.5
PEAK DEMAND(GW)	29.3	5.4	42.3	4.5	52.6	3.9	63.6	3.9	77.0	4.5
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	17.9	2.6	21.5	2.6	24.4	2.6	27.7	2.6	31.5	2.6
TOTAL DEMAND(THOUSAND GWH)	165.3	3.8	215.1	3.3	253.2	3.1	295.1	3.1	344.0	3.4
PEAK DEMAND(GW)	29.3	3.7	37.8	3.4	44.7	3.1	52.2	3.1	60.8	3.4
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	17.9	4.5	24.4	4.0	29.7	3.3	34.9	3.2	40.9	3.8
TOTAL DEMAND(THOUSAND GWH)	165.3	5.8	244.5	4.7	308.1	3.8	371.5	3.7	445.9	4.6
PEAK DEMAND(GW)	29.3	5.6	43.0	4.8	54.4	3.8	65.7	3.7	78.8	4.6
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	17.9	4.3	24.0	3.6	28.7	3.4	33.8	3.4	39.9	3.7
TOTAL DEMAND(THOUSAND GWH)	165.3	5.5	240.7	4.3	297.7	3.9	359.9	3.9	435.7	4.5
PEAK DEMAND(GW)	29.3	5.4	42.3	4.5	52.6	3.9	63.6	3.9	77.0	4.5
MARGIN(PERCENT)			25.0		25.0		25.0		25.0	
RESOURCES TO SERVE DEMAND(GW)			52.9		65.7		79.5		96.2	
LOAD FACTOR(PERCENT)	64.4		65.0		64.6		64.6		64.6	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: WSCC
SUB-REGION: NWPP

SHEET 2 OF 6

CONTRACT NO. DACW72-78-C-0013
DATE MARCH 1980

EXHIBIT X-2

ELECTRIC POWER DEMAND
ROCKY MOUNTAIN POWER AREA
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	3084.	1.7	3470.	1.0	3647.	.7	3776.	7	3911.	1.1
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	8.4	5.6	12.3	4.0	14.9	4.6	18.7	4.0	22.8	4.6
TOTAL DEMAND(THOUSAND GWH)	25.9	7.4	42.6	5.0	54.4	5.4	70.6	4.8	89.2	5.8
PEAK DEMAND(GW)	4.6	7.0	7.4	4.9	9.4	5.4	12.2	4.8	15.4	5.6
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	8.4	2.6	10.1	2.6	11.4	2.6	13.0	2.6	14.8	2.6
TOTAL DEMAND(THOUSAND GWH)	25.9	4.3	34.9	3.6	41.7	3.3	49.1	3.3	57.8	3.7
PEAK DEMAND(GW)	4.6	4.0	6.1	3.5	7.2	3.3	8.5	3.3	10.0	3.6
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	8.4	4.5	11.4	4.0	13.9	3.3	16.4	3.2	19.1	3.8
TOTAL DEMAND(THOUSAND GWH)	25.9	6.3	39.7	5.0	50.7	4.0	61.8	3.9	74.9	4.9
PEAK DEMAND(GW)	4.6	5.9	6.9	4.9	8.8	4.0	10.7	3.9	12.9	4.8
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	8.4	4.5	11.4	4.0	13.9	3.3	16.4	3.2	19.1	3.8
TOTAL DEMAND(THOUSAND GWH)	25.9	6.3	39.7	5.0	50.7	4.0	61.8	3.9	74.9	4.9
PEAK DEMAND(GW)	4.6	5.9	6.9	4.9	8.8	4.0	10.7	3.9	12.9	4.8
MARGIN(PERCENT)			25.0		25.0		25.0		25.0	
RESOURCES TO SERVE DEMAND(GW)			8.6		10.9		13.3		16.2	
LOAD FACTOR(PERCENT)	64.3		65.7		66.1		66.1		66.1	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: WSCC
SUB-REGION: RMPA

SHEET 3 OF 6

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT X-2

ELECTRIC POWER DEMAND
ARIZONA-NEW MEXICO POWER AREA
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	3897.	2.3	4569.	1.5	4922.	1.0	5173.	1.0	5437.	1.5
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	9.6	5.7	14.1	3.2	16.6	3.1	19.3	3.1	22.5	3.9
TOTAL DEMAND(THOUSAND GWH)	37.4	8.1	64.6	4.8	81.5	4.2	100.0	4.1	122.2	5.5
PEAK DEMAND(GW)	7.9	6.5	12.3	4.6	15.4	4.2	18.9	4.1	23.1	5.0
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	9.6	2.6	11.5	2.6	13.1	2.6	14.8	2.6	16.9	2.6
TOTAL DEMAND(THOUSAND GWH)	37.4	5.0	52.5	4.1	64.3	3.6	76.8	3.6	91.8	4.2
PEAK DEMAND(GW)	7.9	3.4	10.0	4.0	12.1	3.6	14.5	3.6	17.3	3.6
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	9.6	4.5	13.1	4.0	15.9	3.3	18.7	3.2	21.9	3.8
TOTAL DEMAND(THOUSAND GWH)	37.4	6.9	59.7	5.6	78.2	4.3	96.7	4.2	119.0	5.4
PEAK DEMAND(GW)	7.9	5.3	11.4	5.4	14.8	4.3	18.3	4.2	22.5	4.9
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	9.6	4.5	13.1	4.0	15.9	3.3	18.7	3.2	21.9	3.8
TOTAL DEMAND(THOUSAND GWH)	37.4	6.9	59.7	5.6	78.2	4.3	96.7	4.2	119.0	5.4
PEAK DEMAND(GW)	7.9	5.3	11.4	5.4	14.8	4.3	18.3	4.2	22.5	4.9
MARGIN(PERCENT)			25.0		25.0		25.0		25.0	
RESOURCES TO SERVE DEMAND(GW)			14.2		18.5		22.8		28.1	
LOAD FACTOR(PERCENT)	54.0		60.0		60.4		60.4		60.4	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: WSCC
SUB-REGION: ARZ-NM

SHEET 4 OF 6

CONTRACT NO. DACW72 - 78 - C - 0013
DATE MARCH 1980

EXHIBIT X-2

ELECTRIC POWER DEMAND
SOUTHERN CALIFORNIA-NEVADA POWER AREA
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	14695.	1.2	15975.	1.1	16873.	.8	17559.	.8	18272.	1.0
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	7.0	2.0	8.0	1.9	8.8	2.6	9.9	2.3	11.2	2.2
TOTAL DEMAND(THOUSAND GWH)	102.3	3.2	127.4	3.0	147.8	3.4	174.6	3.2	204.0	3.2
PEAK DEMAND(GW)	20.1	3.5	25.6	3.0	29.7	3.4	35.1	3.2	41.0	3.3
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	7.0	2.6	8.3	2.6	9.5	2.6	10.8	2.6	12.2	2.6
TOTAL DEMAND(THOUSAND GWH)	102.3	3.8	133.1	3.7	159.8	3.4	189.1	3.4	223.7	3.6
PEAK DEMAND(GW)	20.1	4.2	26.7	3.7	32.1	3.4	38.0	3.4	45.0	3.7
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	7.0	4.5	9.5	4.0	11.5	3.3	13.6	3.2	15.9	3.8
TOTAL DEMAND(THOUSAND GWH)	102.3	5.8	151.3	5.1	194.5	4.1	238.1	4.0	290.0	4.8
PEAK DEMAND(GW)	20.1	6.1	30.4	5.1	39.1	4.1	47.8	4.0	58.3	5.0
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	7.0	2.6	8.3	2.6	9.5	2.6	10.8	2.6	12.2	2.6
TOTAL DEMAND(THOUSAND GWH)	102.3	3.8	133.1	3.7	159.8	3.4	189.1	3.4	223.7	3.6
PEAK DEMAND(GW)	20.1	4.2	26.7	3.7	32.1	3.4	38.0	3.4	45.0	3.7
MARGIN(PERCENT)			25.0		25.0		25.0		25.0	
RESOURCES TO SERVE DEMAND(GW)			33.4		40.2		47.5		56.2	
LOAD FACTOR(PERCENT)	58.1		56.8		56.8		56.8		56.8	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: WSCC
SUB-REGION: SO CAL-NEV

SHEET 5 OF 6

CONTRACT NO. DACW72 78 C 0013
DATE MARCH 1980

EXHIBIT X-2

ELECTRIC POWER DEMAND
NORTHERN CALIFORNIA-NEVADA POWER AREA
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	8610.	1.6	9621.	1.3	10263.	.8	10680.	.8	11115.	1.2
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	9.2	2.1	10.7	2.4	12.0	2.6	13.7	2.8	15.8	2.5
TOTAL DEMAND(THOUSAND GWH)	79.2	3.8	102.7	3.8	123.5	3.4	146.3	3.7	175.2	3.7
PEAK DEMAND(GW)	15.8	3.6	20.3	3.7	24.4	3.4	28.9	3.7	34.6	3.6
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	9.2	2.6	11.0	2.6	12.5	2.6	14.2	2.6	16.2	2.6
TOTAL DEMAND(THOUSAND GWH)	79.2	4.2	105.9	3.9	128.5	3.4	152.0	3.4	179.8	3.8
PEAK DEMAND(GW)	15.8	4.1	20.9	3.9	25.4	3.4	30.0	3.4	35.5	3.8
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	9.2	4.5	12.5	4.0	15.2	3.3	17.9	3.2	21.0	3.8
TOTAL DEMAND(THOUSAND GWH)	79.2	6.2	120.4	5.4	156.3	4.1	191.3	4.0	233.1	5.0
PEAK DEMAND(GW)	15.8	6.0	23.8	5.3	30.9	4.1	37.8	4.0	46.0	5.0
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	9.2	2.6	11.0	2.6	12.5	2.6	14.2	2.6	16.2	2.6
TOTAL DEMAND(THOUSAND GWH)	79.2	4.2	105.9	3.9	128.5	3.4	152.0	3.4	179.8	3.8
PEAK DEMAND(GW)	15.8	4.1	20.9	3.9	25.4	3.4	30.0	3.4	35.5	3.8
MARGIN(PERCENT)			25.0		85.0		25.0		25.0	
RESOURCES TO SERVE DEMAND(GW)			26.2		31.7		37.5		44.4	
LOAD FACTOR(PERCENT)	57.2		57.8		57.8		57.8		57.8	

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THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: WSCC
SUB-REGION: NO CAL-NEV

SHEET 6 OF 6

CONTRACT NO. DACW72-78-C-0013
DATE MARCH 1980

EXHIBIT X-2

WSCC NWPP BONNEVILLE POWER ADMINISTRATION MAIN SYSTEM

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 64.6
SUMMER 61.7
WINTER 75.6

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK) OFF SEASON	SUMMER	WINTER	TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD) OFF-SEASON	SUMMER	WINTER	TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD) OFF-SEASON	SUMMER	WINTER
.0 - 1.0	73.7	67.0	88.5	.015	.035	.018	.015	.038	.018
1.0 - 2.0	72.7	66.0	87.5	.020	.109	.020	.030	.200	.030
2.0 - 3.0	71.7	65.0	86.5	.030	.131	.026	.074	.480	.070
3.0 - 4.0	70.7	64.0	85.5	.030	.140	.041	.105	.665	.103
4.0 - 5.0	69.7	63.0	84.5	.032	.149	.060	.170	.804	.154
5.0 - 6.0	68.7	62.0	83.5	.040	.157	.078	.242	.892	.210
6.0 - 7.0	67.7	61.0	82.5	.050	.169	.114	.328	.943	.297
7.0 - 8.0	66.7	60.0	81.5	.072	.170	.138	.431	1.039	.365
8.0 - 9.0	65.7	59.0	80.5	.087	.172	.150	.582	1.159	.428
9.0 - 10.0	64.7	58.0	79.5	.104	.182	.150	.704	1.188	.493
10.0 - 11.0	63.7	57.0	78.5	.124	.194	.157	.843	1.255	.577
11.0 - 12.0	62.7	56.0	77.5	.155	.221	.160	1.048	1.361	.655
12.0 - 13.0	61.7	55.0	76.5	.180	.235	.160	1.172	1.469	.744
13.0 - 14.0	60.7	54.0	75.5	.197	.240	.162	1.303	1.594	.846
14.0 - 15.0	59.7	53.0	74.5	.203	.240	.170	1.382	1.640	.931
15.0 - 16.0	58.7	52.0	73.5	.232	.240	.179	1.511	1.668	1.038
16.0 - 17.0	57.7	51.0	72.5	.240	.240	.180	1.619	1.680	1.089
17.0 - 18.0	56.7	50.0	71.5	.240	.240	.180	1.670	1.680	1.123
18.0 - 19.0	55.7	49.0	70.5	.240	.240	.202	1.680	1.680	1.192
19.0 - 20.0	54.7	48.0	69.5	.240	.240	.232	1.680	1.680	1.260
20.0 - 21.0	53.7	47.0	68.5	.240	.240	.240	1.680	1.680	1.310
21.0 - 22.0	52.7	46.0	67.5	.240	.240	.240	1.680	1.680	1.360
22.0 - 23.0	51.7	45.0	66.5	.240	.240	.240	1.680	1.680	1.424
23.0 - 24.0	50.7	44.0	65.5	.240	.240	.240	1.680	1.680	1.476
24.0 - 25.0	49.7	43.0	64.5	.240	.240	.240	1.680	1.680	1.562
25.0 - 26.0	48.7	42.0	63.5	.240	.240	.240	1.680	1.680	1.614
26.0 - 27.0	47.7	41.0	62.5	.240	.240	.240	1.680	1.680	1.649
27.0 - 28.0	46.7	40.0	61.5	.240	.240	.240	1.680	1.680	1.673
28.0 - 29.0	45.7	39.0	60.5	.240	.240	.240	1.680	1.680	1.680
29.0 - 30.0	44.7	38.0	59.5	.240	.240	.240	1.680	1.680	1.680

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THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: WSCC
SUB-REGION: NWPP
UTILITY: BPA

SHEET 1 OF 6

CONTRACT NO. DACW72 - 78 - C - 0013

DATE: MARCH 1980

EXHIBIT X-3

WSCC NWPP PACIFIC POWER + LIGHT COMPANY-OREGON-WASHINGTON-CALIFORNIA

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 55.4
SUMMER 58.1
WINTER 71.1

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	71.1	72.2	92.0	.010	.033	.010	.010	.042	.022
1.0 - 2.0	70.1	71.2	91.0	.012	.068	.019	.012	.150	.039
2.0 - 3.0	69.1	70.2	90.0	.023	.070	.024	.027	.273	.056
3.0 - 4.0	68.1	69.2	89.0	.030	.080	.041	.065	.351	.086
4.0 - 5.0	67.1	68.2	88.0	.030	.080	.051	.080	.426	.116
5.0 - 6.0	66.1	67.2	87.0	.039	.095	.064	.128	.517	.148
6.0 - 7.0	65.1	66.2	86.0	.040	.119	.070	.164	.596	.184
7.0 - 8.0	64.1	65.2	85.0	.040	.129	.070	.230	.629	.196
8.0 - 9.0	63.1	64.2	84.0	.057	.135	.080	.291	.647	.256
9.0 - 10.0	62.1	63.2	83.0	.064	.140	.080	.345	.682	.301
10.0 - 11.0	61.1	62.2	82.0	.074	.141	.080	.423	.708	.338
11.0 - 12.0	60.1	61.2	81.0	.097	.150	.085	.516	.776	.389
12.0 - 13.0	59.1	60.2	80.0	.110	.150	.106	.596	.840	.439
13.0 - 14.0	58.1	59.2	79.0	.121	.150	.112	.728	.850	.482
14.0 - 15.0	57.1	58.2	78.0	.133	.150	.120	.819	.861	.526
15.0 - 16.0	56.1	57.2	77.0	.145	.156	.128	.888	.897	.567
16.0 - 17.0	55.1	56.2	76.0	.166	.160	.138	.966	.927	.614
17.0 - 18.0	54.1	55.2	75.0	.170	.165	.162	.993	.964	.725
18.0 - 19.0	53.1	54.2	74.0	.170	.170	.170	1.051	.998	.788
19.0 - 20.0	52.1	53.2	73.0	.170	.170	.170	1.086	1.068	.816
20.0 - 21.0	51.1	52.2	72.0	.170	.174	.170	1.124	1.104	.833
21.0 - 22.0	50.1	51.2	71.0	.172	.180	.170	1.142	1.133	.902
22.0 - 23.0	49.1	50.2	70.0	.180	.180	.170	1.171	1.160	.929
23.0 - 24.0	48.1	49.2	69.0	.188	.180	.170	1.240	1.179	.962
24.0 - 25.0	47.1	48.2	68.0	.190	.187	.179	1.275	1.204	.993
25.0 - 26.0	46.1	47.2	67.0	.190	.193	.180	1.296	1.238	1.024
26.0 - 27.0	45.1	46.2	66.0	.190	.204	.180	1.379	1.281	1.065
27.0 - 28.0	44.1	45.2	65.0	.195	.210	.180	1.445	1.322	1.094
28.0 - 29.0	43.1	44.2	64.0	.212	.225	.180	1.495	1.378	1.130
29.0 - 30.0	42.1	43.2	63.0	.230	.232	.189	1.546	1.429	1.163
30.0 - 31.0	41.1	42.2	62.0	.235	.240	.200	1.599	1.497	1.195
31.0 - 32.0	40.1	41.2	61.0	.240	.240	.200	1.643	1.535	1.219
32.0 - 33.0	39.1	40.2	60.0	.240	.240	.203	1.668	1.576	1.254
33.0 - 34.0	38.1	39.2	59.0	.240	.240	.219	1.680	1.609	1.296
34.0 - 35.0	37.1	38.2	58.0	.240	.240	.238	1.680	1.640	1.350
35.0 - 36.0	36.1	37.2	57.0	.240	.240	.240	1.680	1.641	1.384
36.0 - 37.0	35.1	36.2	56.0	.240	.240	.240	1.680	1.659	1.402
37.0 - 38.0	34.1	35.2	55.0	.240	.240	.240	1.680	1.666	1.436
38.0 - 39.0	33.1	34.2	54.0	.240	.240	.240	1.680	1.670	1.473
39.0 - 40.0	32.1	33.2	53.0	.240	.240	.240	1.680	1.677	1.525
40.0 - 41.0	31.1	32.2	52.0	.240	.240	.240	1.680	1.680	1.583
41.0 - 42.0	30.1	31.2	51.0	.240	.240	.240	1.680	1.680	1.609
42.0 - 43.0	29.1	30.2	50.0	.240	.240	.240	1.680	1.680	1.616
43.0 - 44.0	28.1	29.2	49.0	.240	.240	.240	1.680	1.680	1.622
44.0 - 45.0	27.1	28.2	48.0	.240	.240	.240	1.680	1.680	1.630
45.0 - 46.0	26.1	27.2	47.0	.240	.240	.240	1.680	1.680	1.636

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: WSCC
SUB-REGION: NWPP
UTILITY: PPC

SHEET 2 OF 6

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT X-3

WSCC RMPA PUBLIC SERVICE COMPANY OF COLORADO

YEAR: 1985
WEEKLY LOAD FACTOR: OFF-SEASON 62.9
SUMMER 69.3
WINTER 70.7

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO (PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	76.1	89.2	92.2	.015	.010	.010	.015	.010	.010
1.0 - 2.0	75.1	88.2	91.2	.033	.038	.010	.040	.053	.018
2.0 - 3.0	74.1	87.2	90.2	.079	.040	.010	.101	.067	.024
3.0 - 4.0	73.1	86.2	89.2	.118	.057	.012	.153	.107	.032
4.0 - 5.0	72.1	85.2	88.2	.120	.060	.020	.200	.134	.048
5.0 - 6.0	71.1	84.2	87.2	.128	.070	.020	.326	.195	.056
6.0 - 7.0	70.1	83.2	86.2	.130	.070	.025	.435	.232	.071
7.0 - 8.0	69.1	82.2	85.2	.138	.080	.030	.527	.277	.094
8.0 - 9.0	68.1	81.2	84.2	.140	.090	.037	.583	.312	.127
9.0 - 10.0	67.1	80.2	83.2	.140	.100	.046	.612	.353	.144
10.0 - 11.0	66.1	79.2	82.2	.144	.110	.050	.650	.376	.160
11.0 - 12.0	65.1	78.2	81.2	.159	.110	.054	.723	.404	.185
12.0 - 13.0	64.1	77.2	80.2	.163	.120	.063	.761	.459	.260
13.0 - 14.0	63.1	76.2	79.2	.170	.132	.109	.813	.529	.405
14.0 - 15.0	62.1	75.2	78.2	.170	.140	.122	.854	.587	.462
15.0 - 16.0	61.1	74.2	77.2	.170	.140	.131	.881	.605	.498
16.0 - 17.0	60.1	73.2	76.2	.170	.140	.140	.914	.645	.578
17.0 - 18.0	59.1	72.2	75.2	.174	.140	.143	.973	.659	.652
18.0 - 19.0	58.1	71.2	74.2	.193	.148	.150	1.072	.746	.725
19.0 - 20.0	57.1	70.2	73.2	.200	.150	.150	1.141	.827	.781
20.0 - 21.0	56.1	69.2	72.2	.205	.150	.150	1.205	.876	.800
21.0 - 22.0	55.1	68.2	71.2	.210	.150	.158	1.282	.916	.834
22.0 - 23.0	54.1	67.2	70.2	.210	.151	.166	1.324	.945	.880
23.0 - 24.0	53.1	66.2	69.2	.211	.160	.170	1.385	.963	.911
24.0 - 25.0	52.1	65.2	68.2	.236	.164	.170	1.466	1.002	.943
25.0 - 26.0	51.1	64.2	67.2	.240	.170	.170	1.546	1.021	.978
26.0 - 27.0	50.1	63.2	66.2	.240	.170	.170	1.590	1.058	1.028
27.0 - 28.0	49.1	62.2	65.2	.240	.170	.170	1.618	1.096	1.095
28.0 - 29.0	48.1	61.2	64.2	.240	.170	.170	1.637	1.139	1.162
29.0 - 30.0	47.1	60.2	63.2	.240	.173	.170	1.652	1.157	1.211
30.0 - 31.0	46.1	59.2	62.2	.240	.183	.180	1.668	1.175	1.259
31.0 - 32.0	45.1	58.2	61.2	.240	.190	.180	1.670	1.206	1.304
32.0 - 33.0	44.1	57.2	60.2	.240	.190	.180	1.673	1.263	1.355
33.0 - 34.0	43.1	56.2	59.2	.240	.194	.180	1.680	1.307	1.400
34.0 - 35.0	42.1	55.2	58.2	.240	.210	.180	1.680	1.380	1.435
35.0 - 36.0	41.1	54.2	57.2	.240	.225	.180	1.680	1.464	1.470
36.0 - 37.0	40.1	53.2	56.2	.240	.240	.180	1.680	1.585	1.497
37.0 - 38.0	39.1	52.2	55.2	.240	.240	.180	1.680	1.616	1.527
38.0 - 39.0	38.1	51.2	54.2	.240	.240	.189	1.680	1.634	1.549
39.0 - 40.0	37.1	50.2	53.2	.240	.240	.229	1.680	1.658	1.600
40.0 - 41.0	36.1	49.2	52.2	.240	.240	.240	1.680	1.660	1.637
41.0 - 42.0	35.1	48.2	51.2	.240	.240	.240	1.680	1.673	1.666
42.0 - 43.0	34.1	47.2	50.2	.240	.240	.240	1.680	1.680	1.676
43.0 - 44.0	33.1	46.2	49.2	.240	.240	.240	1.680	1.680	1.680
44.0 - 45.0	32.1	45.2	48.2	.240	.240	.240	1.680	1.680	1.680

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: WSCC
SUB-REGION: RMPA
UTILITY: PSC

SHEET 3 OF 6

CONTRACT NO. DACW72 78 C 0013

DATE: MARCH 1980

EXHIBIT X-3

WSCC ARZ-NM ARIZONIA PUBLIC SERVICE COMPANY

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 46.3

SUMMER 76.2

WINTER 45.1

HYDROELECTRIC PLANT

WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD

SUMMARY OF ENERGY REQUIREMENTS

FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	56.4	95.3	53.0	.026	.018	.019	.026	.021	.044
1.0 - 2.0	55.4	94.3	52.0	.069	.030	.040	.079	.075	.146
2.0 - 3.0	54.4	93.3	51.0	.081	.044	.082	.122	.117	.282
3.0 - 4.0	53.4	92.3	50.0	.102	.050	.116	.220	.150	.408
4.0 - 5.0	52.4	91.3	49.0	.115	.055	.134	.291	.203	.524
5.0 - 6.0	51.4	90.3	48.0	.130	.070	.148	.425	.222	.647
6.0 - 7.0	50.4	89.3	47.0	.130	.070	.150	.545	.262	.741
7.0 - 8.0	49.4	88.3	46.0	.131	.072	.150	.614	.310	.836
8.0 - 9.0	48.4	87.3	45.0	.140	.088	.156	.682	.382	.893
9.0 - 10.0	47.4	86.3	44.0	.145	.100	.168	.753	.428	.933
10.0 - 11.0	46.4	85.3	43.0	.150	.102	.170	.802	.465	.998
11.0 - 12.0	45.4	84.3	42.0	.158	.114	.170	.866	.518	1.068
12.0 - 13.0	44.4	83.3	41.0	.160	.120	.170	.947	.578	1.094
13.0 - 14.0	43.4	82.3	40.0	.160	.120	.173	1.003	.638	1.173
14.0 - 15.0	42.4	81.3	39.0	.167	.120	.182	1.073	.694	1.245
15.0 - 16.0	41.4	80.3	38.0	.175	.127	.190	1.146	.731	1.307
16.0 - 17.0	40.4	79.3	37.0	.180	.130	.190	1.240	.753	1.386
17.0 - 18.0	39.4	78.3	36.0	.191	.130	.202	1.308	.799	1.526
18.0 - 19.0	38.4	77.3	35.0	.207	.139	.227	1.391	.843	1.641
19.0 - 20.0	37.4	76.3	34.0	.213	.140	.240	1.489	.866	1.680
20.0 - 21.0	36.4	75.3	33.0	.236	.140	.240	1.608	.886	1.680
21.0 - 22.0	35.4	74.3	32.0	.240	.148	.240	1.637	.927	1.680
22.0 - 23.0	34.4	73.3	31.0	.240	.150	.240	1.654	.969	1.680
23.0 - 24.0	33.4	72.3	30.0	.240	.160	.240	1.680	.990	1.680
24.0 - 25.0	32.4	71.3	29.0	.240	.160	.240	1.680	1.000	1.680
25.0 - 26.0	31.4	70.3	28.0	.240	.160	.240	1.680	1.027	1.680
26.0 - 27.0	30.4	69.3	27.0	.240	.160	.240	1.680	1.054	1.680
27.0 - 28.0	29.4	68.3	26.0	.240	.160	.240	1.680	1.086	1.680
28.0 - 29.0	28.4	67.3	25.0	.240	.170	.240	1.680	1.128	1.680
29.0 - 30.0	27.4	66.3	24.0	.240	.170	.240	1.680	1.152	1.680
30.0 - 31.0	26.4	65.3	23.0	.240	.170	.240	1.680	1.190	1.680
31.0 - 32.0	25.4	64.3	22.0	.240	.170	.240	1.680	1.222	1.680
32.0 - 33.0	24.4	63.3	21.0	.240	.173	.240	1.680	1.284	1.680
33.0 - 34.0	23.4	62.3	20.0	.240	.181	.240	1.680	1.335	1.680
34.0 - 35.0	22.4	61.3	19.0	.240	.192	.240	1.680	1.419	1.680
35.0 - 36.0	21.4	60.3	18.0	.240	.200	.240	1.680	1.465	1.680
36.0 - 37.0	20.4	59.3	17.0	.240	.200	.240	1.680	1.498	1.680
37.0 - 38.0	19.4	58.3	16.0	.240	.219	.240	1.680	1.553	1.680
38.0 - 39.0	18.4	57.3	15.0	.240	.240	.240	1.680	1.599	1.680
39.0 - 40.0	17.4	56.3	14.0	.240	.240	.240	1.680	1.611	1.680
40.0 - 41.0	16.4	55.3	13.0	.240	.240	.240	1.680	1.639	1.680
41.0 - 42.0	15.4	54.3	12.0	.240	.240	.240	1.680	1.642	1.680
42.0 - 43.0	14.4	53.3	11.0	.240	.240	.240	1.680	1.669	1.680
43.0 - 44.0	13.4	52.3	10.0	.240	.240	.240	1.680	1.680	1.680
44.0 - 45.0	12.4	51.3	9.0	.240	.240	.240	1.680	1.680	1.680

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: WSCC
SUB-REGION: ARZ-NM
UTILITY: APS

SHEET 4 OF 6

CONTRACT NO. DACW72 - 78 - C - 0013

DATE: MARCH 1980

EXHIBIT X-3

WSCC SCA-NV SOUTHERN CALIFORNIA EDISON COMPANY-MAIN SYSTEM

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 56.4
SUMMER 66.2
WINTER 58.3

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO (PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	72.2	89.6	76.2	.025	.010	.010	.034	.012	.021
1.0 - 2.0	71.2	88.6	75.2	.036	.023	.010	.063	.033	.040
2.0 - 3.0	70.2	87.6	74.2	.062	.030	.018	.135	.065	.062
3.0 - 4.0	69.2	86.6	73.2	.080	.032	.037	.208	.108	.124
4.0 - 5.0	68.2	85.6	72.2	.091	.048	.040	.262	.164	.149
5.0 - 6.0	67.2	84.6	71.2	.114	.050	.040	.355	.204	.174
6.0 - 7.0	66.2	83.6	70.2	.120	.050	.040	.432	.235	.199
7.0 - 8.0	65.2	82.6	69.2	.129	.055	.040	.497	.259	.242
8.0 - 9.0	64.2	81.6	68.2	.130	.072	.072	.531	.292	.383
9.0 - 10.0	63.2	80.6	67.2	.130	.080	.104	.566	.315	.535
10.0 - 11.0	62.2	79.6	66.2	.133	.080	.127	.604	.346	.632
11.0 - 12.0	61.2	78.6	65.2	.143	.080	.130	.655	.379	.689
12.0 - 13.0	60.2	77.6	64.2	.150	.087	.130	.712	.443	.706
13.0 - 14.0	59.2	76.6	63.2	.150	.110	.139	.748	.499	.723
14.0 - 15.0	58.2	75.6	62.2	.150	.120	.140	.762	.546	.753
15.0 - 16.0	57.2	74.6	61.2	.150	.120	.147	.786	.591	.786
16.0 - 17.0	56.2	73.6	60.2	.150	.120	.150	.800	.602	.798
17.0 - 18.0	55.2	72.6	59.2	.157	.120	.150	.820	.635	.811
18.0 - 19.0	54.2	71.6	58.2	.165	.123	.150	.875	.648	.859
19.0 - 20.0	53.2	70.6	57.2	.170	.130	.150	.940	.672	.888
20.0 - 21.0	52.2	69.6	56.2	.170	.135	.156	.983	.735	.919
21.0 - 22.0	51.2	68.6	55.2	.170	.140	.160	1.028	.773	.968
22.0 - 23.0	50.2	67.6	54.2	.170	.140	.164	1.045	.807	1.018
23.0 - 24.0	49.2	66.6	53.2	.172	.140	.170	1.054	.853	1.040
24.0 - 25.0	48.2	65.6	52.2	.180	.141	.170	1.107	.867	1.044
25.0 - 26.0	47.2	64.6	51.2	.180	.150	.170	1.186	.904	1.053
26.0 - 27.0	46.2	63.6	50.2	.189	.150	.170	1.235	.942	1.080
27.0 - 28.0	45.2	62.6	49.2	.197	.156	.170	1.275	.972	1.137
28.0 - 29.0	44.2	61.6	48.2	.206	.160	.175	1.334	1.002	1.204
29.0 - 30.0	43.2	60.6	47.2	.227	.160	.186	1.430	1.030	1.249
30.0 - 31.0	42.2	59.6	46.2	.240	.160	.190	1.535	1.040	1.268
31.0 - 32.0	41.2	58.6	45.2	.240	.160	.190	1.593	1.044	1.295
32.0 - 33.0	40.2	57.6	44.2	.240	.160	.190	1.661	1.050	1.341
33.0 - 34.0	39.2	56.6	43.2	.240	.170	.190	1.680	1.085	1.428
34.0 - 35.0	38.2	55.6	42.2	.240	.180	.194	1.680	1.129	1.513
35.0 - 36.0	37.2	54.6	41.2	.240	.180	.206	1.680	1.165	1.581
36.0 - 37.0	36.2	53.6	40.2	.240	.182	.237	1.680	1.182	1.629
37.0 - 38.0	35.2	52.6	39.2	.240	.190	.240	1.680	1.208	1.665
38.0 - 39.0	34.2	51.6	38.2	.240	.194	.240	1.680	1.231	1.680
39.0 - 40.0	33.2	50.6	37.2	.240	.210	.240	1.680	1.291	1.680
40.0 - 41.0	32.2	49.6	36.2	.240	.215	.240	1.680	1.333	1.680
41.0 - 42.0	31.2	48.6	35.2	.240	.238	.240	1.680	1.393	1.680
42.0 - 43.0	30.2	47.6	34.2	.240	.240	.240	1.680	1.472	1.680
43.0 - 44.0	29.2	46.6	33.2	.240	.240	.240	1.680	1.550	1.680
44.0 - 45.0	28.2	45.6	32.2	.240	.240	.240	1.680	1.587	1.680
45.0 - 46.0	27.2	44.6	31.2	.240	.240	.240	1.680	1.624	1.680

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: WSCC
SUB-REGION: SO CAL-NEV
UTILITY: SCE

SHEET 5 OF 6

CONTRACT NO. DACW72 - 78 C - 0013
DATE: MARCH 1980

EXHIBIT X-3

WSCC NCA-NV PACIFIC GAS AND ELECTRIC COMPANY

YEAR: 1985
WEEKLY LOAD FACTOR: OFF-SEASON 58.2
SUMMER 67.7
WINTER 60.5

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO (PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	74.0	87.4	77.3	.010	.022	.010	.010	.022	.025
1.0 - 2.0	73.0	86.4	76.3	.010	.038	.010	.017	.061	.030
2.0 - 3.0	72.0	85.4	75.3	.011	.049	.011	.039	.118	.031
3.0 - 4.0	71.0	84.4	74.3	.031	.054	.020	.102	.161	.067
4.0 - 5.0	70.0	83.4	73.3	.067	.060	.020	.186	.223	.090
5.0 - 6.0	69.0	82.4	72.3	.112	.066	.030	.304	.263	.100
6.0 - 7.0	68.0	81.4	71.3	.122	.072	.040	.419	.313	.133
7.0 - 8.0	67.0	80.4	70.3	.130	.091	.043	.516	.352	.178
8.0 - 9.0	66.0	79.4	69.3	.130	.110	.071	.570	.407	.250
9.0 - 10.0	65.0	78.4	68.3	.130	.110	.080	.603	.475	.373
10.0 - 11.0	64.0	77.4	67.3	.132	.116	.084	.636	.535	.456
11.0 - 12.0	63.0	76.4	66.3	.140	.120	.111	.675	.581	.590
12.0 - 13.0	62.0	75.4	65.3	.147	.120	.132	.723	.593	.721
13.0 - 14.0	61.0	74.4	64.3	.150	.123	.140	.755	.603	.800
14.0 - 15.0	60.0	73.4	63.3	.150	.134	.149	.765	.630	.871
15.0 - 16.0	59.0	72.4	62.3	.150	.140	.150	.787	.670	.896
16.0 - 17.0	58.0	71.4	61.3	.150	.140	.151	.812	.720	.907
17.0 - 18.0	57.0	70.4	60.3	.152	.140	.160	.847	.738	.944
18.0 - 19.0	56.0	69.4	59.3	.167	.140	.160	.912	.752	.996
19.0 - 20.0	55.0	68.4	58.3	.170	.140	.160	.950	.784	1.049
20.0 - 21.0	54.0	67.4	57.3	.170	.153	.168	1.011	.833	1.068
21.0 - 22.0	53.0	66.4	56.3	.170	.160	.170	1.026	.872	1.107
22.0 - 23.0	52.0	65.4	55.3	.170	.160	.170	1.047	.912	1.142
23.0 - 24.0	51.0	64.4	54.3	.172	.160	.170	1.091	.946	1.162
24.0 - 25.0	50.0	63.4	53.3	.180	.160	.170	1.164	.964	1.170
25.0 - 26.0	49.0	62.4	52.3	.183	.160	.170	1.223	.990	1.197
26.0 - 27.0	48.0	61.4	51.3	.190	.160	.176	1.260	1.017	1.216
27.0 - 28.0	47.0	60.4	50.3	.195	.166	.187	1.296	1.051	1.247
28.0 - 29.0	46.0	59.4	49.3	.205	.180	.190	1.352	1.100	1.299
29.0 - 30.0	45.0	58.4	48.3	.216	.180	.190	1.421	1.152	1.318
30.0 - 31.0	44.0	57.4	47.3	.240	.180	.190	1.527	1.174	1.355
31.0 - 32.0	43.0	56.4	46.3	.240	.180	.200	1.594	1.192	1.425
32.0 - 33.0	42.0	55.4	45.3	.240	.180	.204	1.663	1.206	1.521
33.0 - 34.0	41.0	54.4	44.3	.240	.199	.223	1.680	1.277	1.605
34.0 - 35.0	40.0	53.4	43.3	.240	.200	.240	1.680	1.313	1.672
35.0 - 36.0	39.0	52.4	42.3	.240	.206	.240	1.680	1.347	1.680
36.0 - 37.0	38.0	51.4	41.3	.240	.228	.240	1.680	1.443	1.680
37.0 - 38.0	37.0	50.4	40.3	.240	.240	.240	1.680	1.506	1.680
38.0 - 39.0	36.0	49.4	39.3	.240	.240	.240	1.680	1.578	1.680
39.0 - 40.0	35.0	48.4	38.3	.240	.240	.240	1.680	1.615	1.680
40.0 - 41.0	34.0	47.4	37.3	.240	.240	.240	1.680	1.655	1.680
41.0 - 42.0	33.0	46.4	36.3	.240	.240	.240	1.680	1.675	1.680
42.0 - 43.0	32.0	45.4	35.3	.240	.240	.240	1.680	1.680	1.680
43.0 - 44.0	31.0	44.4	34.3	.240	.240	.240	1.680	1.680	1.680

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
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CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: WSCC
SUB-REGION: NO CAL-NEV
UTILITY: PG&E

CONTRACT NO. DACW72 78 C 0013
DATE: MARCH 1980

EXHIBIT X-3

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
ALASKA

SERVICE AREA APPROXIMATED BY BEA AREAS:
172

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	21.	23.	24.	29.
MINING	46.	56.	68.	90.
CONSTRUCTION	180.	211.	247.	332.
MANUFACTURING	115.	135.	159.	215.
TRANSPO UTILITIES	176.	215.	262.	381.
TRADE	192.	229.	273.	386.
FINANCE	54.	69.	87.	135.
SERVICES	204.	263.	339.	542.
GOVERNMENT	724.	862.	1026.	1447.
TOTAL EARNINGS (MILLION $)	1713.	2064.	2487.	3557.
TOTAL PERSONAL INCOME (MILLION $)	1875.	2289.	2795.	4088.
TOTAL POPULATION (THOUSANDS)	333.	361.	391.	438.
PER CAPITA INCOME ($)	5626.	6340.	7145.	9333.
PER CAPTA INCOME RELATIVE TO U. S.	1.18	1.17	1.16	1.14

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: ALASKA
SUB-REGION: ALASKA

SHEET 1 OF 1

CONTRACT NO. DACW72 - 78 - C - 0013
DATE: MARCH 1980

EXHIBIT XI-1

ELECTRIC POWER DEMAND
STATE OF ALASKA
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	403.	2.6	483.	1.6	523.	1.1	552.	1.1	583.	1.7
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	5.6	12.3	12.6	4.2	15.5	5.7	20.5	4.0	24.9	7.0
TOTAL DEMAND(THOUSAND GWH)	2.3	15.2	6.1	5.8	8.1	6.9	11.3	5.1	14.5	8.8
PEAK DEMAND(GW)	.5	14.6	1.4	5.7	1.8	6.9	2.6	5.1	3.3	8.6
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	5.6	2.6	6.7	2.6	7.6	2.6	8.7	2.6	9.9	2.6
TOTAL DEMAND(THOUSAND GWH)	2.3	5.3	3.2	4.2	4.0	3.7	4.8	3.7	5.8	4.3
PEAK DEMAND(GW)	.5	4.7	.7	4.1	.9	3.7	1.1	3.7	1.3	4.1
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	5.6	4.5	7.6	4.0	9.3	3.3	10.9	3.2	12.8	3.8
TOTAL DEMAND(THOUSAND GWH)	2.3	7.2	3.7	5.7	4.9	4.4	6.0	4.3	7.5	5.6
PEAK DEMAND(GW)	.5	6.6	.8	5.6	1.1	4.4	1.4	4.3	1.7	5.4
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	5.6	4.5	7.6	4.0	9.3	3.3	10.9	3.2	12.8	3.8
TOTAL DEMAND(THOUSAND GWH)	2.3	7.2	3.7	5.7	4.9	4.4	6.0	4.3	7.5	5.6
PEAK DEMAND(GW)	.5	6.6	.8	5.6	1.1	4.4	1.4	4.3	1.7	5.4
MARGIN(PERCENT)			47.3		50.0		50.0		50.0	
RESOURCES TO SERVE DEMAND(GW)			1.2		1.7		2.1		2.6	
LOAD FACTOR(PERCENT)	47.8		49.7		50.0		50.0		50.0	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

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THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: ALASKA
SUB-REGION: ALASKA

SHEET 1 OF 1

CONTRACT NO. DACW72 78 C 0013
DATE: MARCH 1980

EXHIBIT XI-2

ALASKA CHUGACH ELECTRIC ASSOCIATION, INC.

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 48.7
SUMMER 39.0
WINTER 85.6

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	60.4	46.4	99.0	.012	.020	.015	.012	.057	.015
1.0 - 2.0	59.4	45.4	98.0	.020	.064	.020	.028	.196	.056
2.0 - 3.0	58.4	44.4	97.0	.026	.110	.026	.056	.409	.111
3.0 - 4.0	57.4	43.4	96.0	.030	.127	.039	.101	.586	.172
4.0 - 5.0	56.4	42.4	95.0	.038	.140	.040	.138	.790	.232
5.0 - 6.0	55.4	41.4	94.0	.040	.140	.044	.198	.890	.264
6.0 - 7.0	54.4	40.4	93.0	.043	.144	.060	.257	.959	.344
7.0 - 8.0	53.4	39.4	92.0	.080	.152	.067	.410	1.028	.409
8.0 - 9.0	52.4	38.4	91.0	.097	.160	.077	.572	1.076	.505
9.0 - 10.0	51.4	37.4	90.0	.120	.160	.088	.717	1.084	.581
10.0 - 11.0	50.4	36.4	89.0	.130	.160	.103	.798	1.090	.659
11.0 - 12.0	49.4	35.4	88.0	.150	.160	.116	.894	1.094	.761
12.0 - 13.0	48.4	34.4	87.0	.156	.168	.132	.994	1.159	.844
13.0 - 14.0	47.4	33.4	86.0	.164	.176	.140	1.063	1.200	.916
14.0 - 15.0	46.4	32.4	85.0	.170	.180	.147	1.118	1.220	.997
15.0 - 16.0	45.4	31.4	84.0	.170	.180	.160	1.151	1.230	1.065
16.0 - 17.0	44.4	30.4	83.0	.170	.180	.162	1.168	1.262	1.107
17.0 - 18.0	43.4	29.4	82.0	.170	.185	.170	1.176	1.320	1.143
18.0 - 19.0	42.4	28.4	81.0	.171	.196	.170	1.206	1.433	1.154
19.0 - 20.0	41.4	27.4	80.0	.180	.209	.170	1.247	1.542	1.166
20.0 - 21.0	40.4	26.4	79.0	.188	.237	.170	1.293	1.654	1.199
21.0 - 22.0	39.4	25.4	78.0	.190	.240	.178	1.349	1.672	1.226
22.0 - 23.0	38.4	24.4	77.0	.211	.240	.190	1.451	1.680	1.277
23.0 - 24.0	37.4	23.4	76.0	.231	.240	.190	1.596	1.680	1.282
24.0 - 25.0	36.4	22.4	75.0	.240	.240	.190	1.655	1.680	1.311
25.0 - 26.0	35.4	21.4	74.0	.240	.240	.190	1.680	1.680	1.361
26.0 - 27.0	34.4	20.4	73.0	.240	.240	.197	1.680	1.680	1.452
27.0 - 28.0	33.4	19.4	72.0	.240	.240	.201	1.680	1.680	1.528
28.0 - 29.0	32.4	18.4	71.0	.240	.240	.225	1.680	1.680	1.593
29.0 - 30.0	31.4	17.4	70.0	.240	.240	.240	1.680	1.680	1.625
30.0 - 31.0	30.4	16.4	69.0	.240	.240	.240	1.680	1.680	1.630
31.0 - 32.0	29.4	15.4	68.0	.240	.240	.240	1.680	1.680	1.634
32.0 - 33.0	28.4	14.4	67.0	.240	.240	.240	1.680	1.680	1.663
33.0 - 34.0	27.4	13.4	66.0	.240	.240	.240	1.680	1.680	1.680
34.0 - 35.0	26.4	12.4	65.0	.240	.240	.240	1.680	1.680	1.680

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THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: ALASKA
SUB-REGION: ALASKA
UTILITY: CEA

SHEET 1 OF 3

CONTRACT NO. DACW72-78-C-0013
DATE: MARCH 1980

EXHIBIT XI-3

ALASKA GOLDEN VALLEY ELECTRIC ASSOCIATION, INC.

YEAR: 1985
WEEKLY LOAD FACTOR: OFF-SEASON 44.1
SUMMER 30.3
WINTER 79.5

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	54.9	38.7	90.3	.010	.010	.016	.010	.012	.016
1.0 - 2.0	53.9	37.7	89.3	.010	.014	.020	.014	.063	.022
2.0 - 3.0	52.9	36.7	88.3	.010	.020	.023	.021	.158	.050
3.0 - 4.0	51.9	35.7	87.3	.010	.032	.049	.050	.319	.108
4.0 - 5.0	50.9	34.7	86.3	.010	.053	.088	.100	.491	.228
5.0 - 6.0	49.9	33.7	85.3	.016	.073	.099	.180	.601	.322
6.0 - 7.0	48.9	32.7	84.3	.038	.120	.120	.272	.746	.456
7.0 - 8.0	47.9	31.7	83.3	.058	.150	.131	.400	.903	.576
8.0 - 9.0	46.9	30.7	82.3	.066	.150	.140	.537	.983	.678
9.0 - 10.0	45.9	29.7	81.3	.082	.150	.149	.646	1.033	.818
10.0 - 11.0	44.9	28.7	80.3	.090	.163	.160	.744	1.098	.933
11.0 - 12.0	43.9	27.7	79.3	.107	.170	.160	.874	1.138	1.011
12.0 - 13.0	42.9	26.7	78.3	.122	.170	.162	.987	1.150	1.049
13.0 - 14.0	41.9	25.7	77.3	.143	.170	.180	1.089	1.157	1.081
14.0 - 15.0	40.9	24.7	76.3	.150	.171	.180	1.168	1.187	1.106
15.0 - 16.0	39.9	23.7	75.3	.160	.180	.180	1.237	1.241	1.112
16.0 - 17.0	38.9	22.7	74.3	.160	.188	.180	1.304	1.291	1.152
17.0 - 18.0	37.9	21.7	73.3	.160	.190	.180	1.361	1.359	1.178
18.0 - 19.0	36.9	20.7	72.3	.162	.207	.180	1.428	1.419	1.231
19.0 - 20.0	35.9	19.7	71.3	.193	.226	.197	1.522	1.519	1.336
20.0 - 21.0	34.9	18.7	70.3	.212	.236	.201	1.623	1.631	1.426
21.0 - 22.0	33.9	17.7	69.3	.220	.240	.228	1.656	1.676	1.516
22.0 - 23.0	32.9	16.7	68.3	.220	.240	.236	1.660	1.680	1.578
23.0 - 24.0	31.9	15.7	67.3	.222	.240	.240	1.662	1.680	1.599
24.0 - 25.0	30.9	14.7	66.3	.231	.240	.240	1.671	1.680	1.636
25.0 - 26.0	29.9	13.7	65.3	.240	.240	.240	1.680	1.680	1.669
26.0 - 27.0	28.9	12.7	64.3	.240	.240	.240	1.680	1.680	1.670
27.0 - 28.0	27.9	11.7	63.3	.240	.240	.240	1.680	1.680	1.679
28.0 - 29.0	26.9	10.7	62.3	.240	.240	.240	1.680	1.680	1.680
29.0 - 30.0	25.9	9.7	61.3	.240	.240	.240	1.680	1.680	1.680

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: ALASKA
SUB-REGION: ALASKA
UTILITY: GVEA

SHEET 2 OF 3

CONTRACT NO. DACW72 78-C-0013
DATE: MARCH 1980

EXHIBIT XI-3

ALASKA FAIRBANKS MUNICIPAL UTILITIES SYSTEM

YEAR: 1985
WEEKLY LOAD FACTOR: OFF-SEASON 56.8
SUMMER 53.1
WINTER 76.7

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO (PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	73.3	66.1	91.9	.035	.010	.022	.035	.026	.048
1.0 - 2.0	72.3	65.1	90.9	.052	.040	.064	.052	.152	.177
2.0 - 3.0	71.3	64.1	89.9	.060	.055	.070	.060	.251	.226
3.0 - 4.0	70.3	63.1	88.9	.073	.064	.074	.073	.346	.301
4.0 - 5.0	69.3	62.1	87.9	.108	.074	.084	.108	.398	.378
5.0 - 6.0	68.3	61.1	86.9	.133	.080	.090	.133	.436	.416
6.0 - 7.0	67.3	60.1	85.9	.140	.080	.090	.178	.449	.445
7.0 - 8.0	66.3	59.1	84.9	.140	.094	.096	.274	.482	.492
8.0 - 9.0	65.3	58.1	83.9	.140	.109	.110	.354	.566	.525
9.0 - 10.0	64.3	57.1	82.9	.147	.134	.110	.444	.674	.570
10.0 - 11.0	63.3	56.1	81.9	.150	.143	.120	.512	.782	.638
11.0 - 12.0	62.3	55.1	80.9	.150	.156	.120	.569	.864	.681
12.0 - 13.0	61.3	54.1	79.9	.151	.160	.125	.650	.911	.695
13.0 - 14.0	60.3	53.1	78.9	.160	.160	.130	.693	.977	.736
14.0 - 15.0	59.3	52.1	77.9	.160	.160	.130	.728	1.014	.768
15.0 - 16.0	58.3	51.1	76.9	.160	.160	.130	.771	1.046	.809
16.0 - 17.0	57.3	50.1	75.9	.160	.166	.149	.826	1.058	.875
17.0 - 18.0	56.3	49.1	74.9	.160	.170	.150	.845	1.087	.904
18.0 - 19.0	55.3	48.1	73.9	.160	.170	.150	.851	1.109	.920
19.0 - 20.0	54.3	47.1	72.9	.160	.170	.154	.926	1.164	.971
20.0 - 21.0	53.3	46.1	71.9	.163	.180	.160	1.021	1.180	1.009
21.0 - 22.0	52.3	45.1	70.9	.170	.180	.160	1.070	1.199	1.032
22.0 - 23.0	51.3	44.1	69.9	.170	.180	.160	1.100	1.210	1.072
23.0 - 24.0	50.3	43.1	68.9	.170	.180	.176	1.110	1.220	1.119
24.0 - 25.0	49.3	42.1	67.9	.170	.194	.180	1.131	1.252	1.161
25.0 - 26.0	48.3	41.1	66.9	.170	.200	.180	1.173	1.286	1.203
26.0 - 27.0	47.3	40.1	65.9	.170	.200	.182	1.221	1.346	1.236
27.0 - 28.0	46.3	39.1	64.9	.180	.210	.190	1.298	1.409	1.293
28.0 - 29.0	45.3	38.1	63.9	.195	.221	.194	1.394	1.483	1.342
29.0 - 30.0	44.3	37.1	62.9	.214	.237	.207	1.489	1.545	1.437
30.0 - 31.0	43.3	36.1	61.9	.240	.240	.213	1.597	1.605	1.544
31.0 - 32.0	42.3	35.1	60.9	.240	.240	.235	1.648	1.644	1.618
32.0 - 33.0	41.3	34.1	59.9	.240	.240	.240	1.665	1.669	1.657
33.0 - 34.0	40.3	33.1	58.9	.240	.240	.240	1.678	1.678	1.676
34.0 - 35.0	39.3	32.1	57.9	.240	.240	.240	1.680	1.680	1.680
35.0 - 36.0	38.3	31.1	56.9	.240	.240	.240	1.680	1.680	1.680

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO, ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: ALASKA
SUB-REGION: ALASKA
UTILITY: FMU

SHEET 3 OF 3

CONTRACT NO. DACW72 78 C 0013
DATE: MARCH 1980

EXHIBIT XI-3

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS

POWER SERVICE AREA:
HAWAII

SERVICE AREA APPROXIMATED BY BEA AREAS:
173

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	107.	110.	114.	128.
MINING	0.	0.	0.	0.
CONSTRUCTION	317.	370.	432.	580.
MANUFACTURING	255.	295.	342.	455.
TRANSPO UTILITIES	329.	399.	483.	697.
TRADE	549.	643.	752.	1035.
FINANCE	262.	324.	400.	598.
SERVICES	712.	896.	1127.	1721.
GOVERNMENT	1211.	1443.	1721.	2431.
TOTAL EARNINGS (MILLION $)	3741.	4483.	5372.	7646.
TOTAL PERSONAL INCOME (MILLION $)	4555.	5502.	6645.	9575.
TOTAL POPULATION (THOUSANDS)	847.	911.	979.	1085.
PER CAPITA INCOME ($)	5375.	6042.	6791.	8823.
PER CAPTA INCOME RELATIVE TO U. S.	1.12	1.11	1.10	1.08

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTED POPULATION, INCOME & EARNINGS

REGION: HAWAII

SUB-REGION: HAWAII

SHEET 1 OF 1

CONTRACT NO. DACW72-78-C-0013

DATE: MARCH 1980

EXHIBIT XII-1

ELECTRIC POWER DEMAND
STATE OF HAWAII
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	897.	1.7	1007.	1.4	1080.	1.0	1135.	1.0	1193.	1.3
PROJECTION I										
PER CAPITA CONSUMPTION (MWH)	7.5	1.8	8.6	1.7	9.3	2.1	10.3	2.1	11.5	1.9
TOTAL DEMAND(THOUSAND GWH)	6.8	3.5	8.6	3.1	10.0	3.2	11.7	3.1	13.7	3.2
PEAK DEMAND(GW)	1.1	3.7	1.4	3.0	1.7	3.2	1.9	3.1	2.3	3.3
PROJECTION II										
PER CAPITA CONSUMPTION (MWH)	7.5	2.6	9.0	2.6	10.3	2.6	11.7	2.6	13.3	2.6
TOTAL DEMAND(THOUSAND GWH)	6.8	4.3	9.1	4.0	11.1	3.6	13.2	3.6	15.8	3.9
PEAK DEMAND(GW)	1.1	4.5	1.5	4.0	1.8	3.6	2.2	3.6	2.6	4.0
PROJECTION III										
PER CAPITA CONSUMPTION (MWH)	7.5	4.5	10.3	4.0	12.5	3.3	14.7	3.2	17.2	3.8
TOTAL DEMAND(THOUSAND GWH)	6.8	6.2	10.3	5.5	13.5	4.3	16.7	4.2	20.5	5.2
PEAK DEMAND(GW)	1.1	6.4	1.7	5.4	2.2	4.3	2.8	4.2	3.4	5.2
MEDIAN PROJECTION										
PER CAPITA CONSUMPTION (MWH)	7.5	2.6	9.0	2.6	10.3	2.6	11.7	2.6	13.3	2.6
TOTAL DEMAND(THOUSAND GWH)	6.8	4.3	9.1	4.0	11.1	3.6	13.2	3.6	15.8	3.9
PEAK DEMAND(GW)	1.1	4.5	1.5	4.0	1.8	3.6	2.2	3.6	2.6	4.0
MARGIN(PERCENT)			25.0		25.0		25.0		25.0	
RESOURCES TO SERVE DEMAND(GW)			1.9		2.3		2.7		3.3	
LOAD FACTOR(PERCENT)	69.5		68.7		69.0		69.0		69.0	

*NOTE: THE GROWTH RATES ARE AVERAGE ANNUAL COMPOUNDED RATES OVER THE PERIOD.

HARZA ENGINEERING COMPANY
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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

PROJECTIONS OF ELECTRIC POWER DEMAND

REGION: HAWAII

SUB-REGION: HAWAII

SHEET 1 OF 1

CONTRACT NO. DACW72-78-C-0013

DATE MARCH 1980

EXHIBIT XII-2

HAWAII HAWAIIAN ELECTRIC COMPANY

YEAR: 1985
WEEKLY LOAD FACTOR: OFF-SEASON 66.1
SUMMER 71.9
WINTER 70.8

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO (PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	88.1	97.2	97.9	.010	.010	.010	.018	.010	.020
1.0 - 2.0	87.1	96.2	96.9	.010	.010	.010	.036	.010	.029
2.0 - 3.0	86.1	95.2	95.9	.010	.010	.010	.045	.010	.040
3.0 - 4.0	85.1	94.2	94.9	.015	.010	.010	.055	.010	.046
4.0 - 5.0	84.1	93.2	93.9	.030	.010	.013	.086	.010	.070
5.0 - 6.0	83.1	92.2	92.9	.040	.010	.025	.120	.010	.088
6.0 - 7.0	82.1	91.2	91.9	.041	.010	.030	.140	.011	.100
7.0 - 8.0	81.1	90.2	90.9	.060	.010	.030	.169	.034	.100
8.0 - 9.0	80.1	89.2	89.9	.069	.019	.030	.215	.084	.108
9.0 - 10.0	79.1	88.2	88.9	.100	.022	.030	.329	.146	.116
10.0 - 11.0	78.1	87.2	87.9	.112	.044	.030	.427	.245	.134
11.0 - 12.0	77.1	86.2	86.9	.120	.068	.030	.532	.338	.176
12.0 - 13.0	76.1	85.2	85.9	.120	.090	.031	.596	.418	.216
13.0 - 14.0	75.1	84.2	84.9	.139	.107	.087	.665	.502	.384
14.0 - 15.0	74.1	83.2	83.9	.140	.119	.113	.718	.536	.505
15.0 - 16.0	73.1	82.2	82.9	.140	.130	.120	.757	.598	.586
16.0 - 17.0	72.1	81.2	81.9	.140	.136	.120	.779	.655	.636
17.0 - 18.0	71.1	80.2	80.9	.140	.140	.129	.809	.708	.669
18.0 - 19.0	70.1	79.2	79.9	.140	.140	.130	.828	.739	.690
19.0 - 20.0	69.1	78.2	78.9	.140	.140	.130	.854	.784	.721
20.0 - 21.0	68.1	77.2	77.9	.140	.140	.130	.883	.818	.735
21.0 - 22.0	67.1	76.2	76.9	.144	.140	.134	.924	.839	.756
22.0 - 23.0	66.1	75.2	75.9	.155	.147	.145	.971	.880	.788
23.0 - 24.0	65.1	74.2	74.9	.160	.150	.150	1.018	.891	.853
24.0 - 25.0	64.1	73.2	73.9	.160	.150	.150	1.047	.909	.875
25.0 - 26.0	63.1	72.2	72.9	.160	.150	.150	1.063	.946	.898
26.0 - 27.0	62.1	71.2	71.9	.160	.159	.150	1.070	.976	.934
27.0 - 28.0	61.1	70.2	70.9	.160	.160	.150	1.075	1.016	.940
28.0 - 29.0	60.1	69.2	69.9	.160	.160	.150	1.090	1.043	.943
29.0 - 30.0	59.1	68.2	68.9	.160	.160	.154	1.097	1.071	.962
30.0 - 31.0	58.1	67.2	67.9	.160	.160	.170	1.103	1.084	1.000
31.0 - 32.0	57.1	66.2	66.9	.163	.160	.170	1.133	1.090	1.027
32.0 - 33.0	56.1	65.2	65.9	.170	.160	.170	1.187	1.092	1.065
33.0 - 34.0	55.1	64.2	64.9	.170	.160	.170	1.196	1.110	1.097
34.0 - 35.0	54.1	63.2	63.9	.170	.160	.170	1.200	1.111	1.117
35.0 - 36.0	53.1	62.2	62.9	.174	.160	.170	1.205	1.123	1.140
36.0 - 37.0	52.1	61.2	61.9	.180	.174	.170	1.220	1.170	1.140
37.0 - 38.0	51.1	60.2	60.9	.180	.180	.170	1.235	1.194	1.150
38.0 - 39.0	50.1	59.2	59.9	.183	.180	.170	1.252	1.211	1.161
39.0 - 40.0	49.1	58.2	58.9	.190	.180	.170	1.294	1.222	1.179
40.0 - 41.0	48.1	57.2	57.9	.190	.180	.170	1.321	1.235	1.180
41.0 - 42.0	47.1	56.2	56.9	.190	.180	.171	1.341	1.240	1.191
42.0 - 43.0	46.1	55.2	55.9	.190	.184	.180	1.366	1.250	1.215
43.0 - 44.0	45.1	54.2	54.9	.194	.190	.180	1.390	1.271	1.223
44.0 - 45.0	44.1	53.2	53.9	.200	.190	.180	1.424	1.314	1.230
45.0 - 46.0	43.1	52.2	52.9	.200	.190	.187	1.470	1.339	1.238

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: HAWAII
SUB-REGION: HAWAII
UTILITY: HECO

SHEET 1 OF 4

CONTRACT NO. DACW72 - 78 - C - 0013
DATE MARCH 1980

EXHIBIT XII-3

HAWAII MAUI ELECTRIC CO. LTD.

YEAR: 1985
WEEKLY LOAD FACTOR: OFF-SEASON 58.3
SUMMER 66.9
WINTER 62.1

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	81.1	90.7	91.6	.010	.010	.010	.032	.013	.019
1.0 - 2.0	80.1	89.7	90.6	.011	.010	.010	.070	.023	.039
2.0 - 3.0	79.1	88.7	89.6	.020	.010	.010	.096	.040	.046
3.0 - 4.0	78.1	87.7	88.6	.020	.015	.010	.110	.055	.050
4.0 - 5.0	77.1	86.7	87.6	.020	.020	.010	.113	.066	.050
5.0 - 6.0	76.1	85.7	86.6	.027	.032	.014	.140	.099	.054
6.0 - 7.0	75.1	84.7	85.6	.030	.041	.020	.168	.137	.073
7.0 - 8.0	74.1	83.7	84.6	.030	.071	.020	.199	.199	.090
8.0 - 9.0	73.1	82.7	83.6	.030	.088	.020	.238	.273	.095
9.0 - 10.0	72.1	81.7	82.6	.030	.091	.020	.269	.316	.125
10.0 - 11.0	71.1	80.7	81.6	.040	.113	.023	.313	.391	.139
11.0 - 12.0	70.1	79.7	80.6	.052	.120	.030	.368	.485	.155
12.0 - 13.0	69.1	78.7	79.6	.061	.120	.030	.444	.556	.165
13.0 - 14.0	68.1	77.7	78.6	.070	.124	.032	.487	.634	.182
14.0 - 15.0	67.1	76.7	77.6	.070	.130	.040	.525	.679	.215
15.0 - 16.0	66.1	75.7	76.6	.072	.136	.040	.624	.727	.254
16.0 - 17.0	65.1	74.7	75.6	.096	.140	.050	.692	.758	.309
17.0 - 18.0	64.1	73.7	74.6	.119	.140	.061	.782	.775	.369
18.0 - 19.0	63.1	72.7	73.6	.130	.140	.070	.854	.802	.428
19.0 - 20.0	62.1	71.7	72.6	.138	.140	.073	.902	.828	.454
20.0 - 21.0	61.1	70.7	71.6	.140	.140	.098	.921	.842	.540
21.0 - 22.0	60.1	69.7	70.6	.140	.140	.120	.956	.865	.632
22.0 - 23.0	59.1	68.7	69.6	.140	.146	.120	.984	.883	.689
23.0 - 24.0	58.1	67.7	68.6	.140	.150	.122	.990	.898	.738
24.0 - 25.0	57.1	66.7	67.6	.143	.150	.140	1.007	.912	.801
25.0 - 26.0	56.1	65.7	66.6	.150	.150	.140	1.032	.946	.815
26.0 - 27.0	55.1	64.7	65.6	.150	.150	.140	1.043	.987	.832
27.0 - 28.0	54.1	63.7	64.6	.154	.150	.140	1.063	1.016	.854
28.0 - 29.0	53.1	62.7	63.6	.160	.150	.140	1.079	1.039	.880
29.0 - 30.0	52.1	61.7	62.6	.160	.150	.140	1.100	1.047	.904
30.0 - 31.0	51.1	60.7	61.6	.160	.150	.140	1.109	1.089	.935
31.0 - 32.0	50.1	59.7	60.6	.160	.159	.140	1.119	1.119	.962
32.0 - 33.0	49.1	58.7	59.6	.160	.160	.151	1.120	1.120	.991
33.0 - 34.0	48.1	57.7	58.6	.162	.160	.160	1.127	1.120	1.024
34.0 - 35.0	47.1	56.7	57.6	.170	.160	.160	1.165	1.121	1.052
35.0 - 36.0	46.1	55.7	56.6	.176	.161	.160	1.196	1.131	1.060
36.0 - 37.0	45.1	54.7	55.6	.180	.180	.160	1.210	1.162	1.076
37.0 - 38.0	44.1	53.7	54.6	.180	.180	.160	1.219	1.171	1.090
38.0 - 39.0	43.1	52.7	53.6	.180	.180	.160	1.238	1.197	1.098
39.0 - 40.0	42.1	51.7	52.6	.180	.180	.161	1.243	1.228	1.129
40.0 - 41.0	41.1	50.7	51.6	.180	.187	.170	1.276	1.255	1.160
41.0 - 42.0	40.1	49.7	50.6	.180	.190	.170	1.301	1.279	1.165
42.0 - 43.0	39.1	48.7	49.6	.182	.190	.170	1.335	1.299	1.172
43.0 - 44.0	38.1	47.7	48.6	.190	.190	.170	1.383	1.304	1.191
44.0 - 45.0	37.1	46.7	47.6	.200	.197	.170	1.414	1.329	1.224
						[illegible]	[illegible]	1.356	1.242

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: HAWAII
SUB-REGION: HAWAII
UTILITY: MECO

SHEET 2 OF 4

CONTRACT NO. DACW72-78-C-0013
DATE: MARCH 1980
EXHIBIT XII-3

HAWAII HAWAIIAN ELECTRIC LIGHT COMPANY, INC.

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 62.2
SUMMER 62.2
WINTER 63.2

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	89.1	84.2	96.4	.010	.010	.010	.019	.010	.014
1.0 - 2.0	88.1	83.2	95.4	.010	.014	.019	.024	.028	.029
2.0 - 3.0	87.1	82.2	94.4	.010	.020	.020	.030	.058	.030
3.0 - 4.0	86.1	81.2	93.4	.010	.020	.020	.030	.087	.030
4.0 - 5.0	85.1	80.2	92.4	.010	.030	.020	.037	.110	.030
5.0 - 6.0	84.1	79.2	91.4	.026	.030	.020	.066	.126	.032
6.0 - 7.0	83.1	78.2	90.4	.030	.036	.020	.097	.146	.041
7.0 - 8.0	82.1	77.2	89.4	.030	.040	.020	.110	.159	.061
8.0 - 9.0	81.1	76.2	88.4	.030	.047	.020	.116	.198	.084
9.0 - 10.0	80.1	75.2	87.4	.030	.078	.020	.140	.283	.099
10.0 - 11.0	79.1	74.2	86.4	.030	.113	.020	.140	.388	.100
11.0 - 12.0	78.1	73.2	85.4	.034	.130	.020	.161	.502	.101
12.0 - 13.0	77.1	72.2	84.4	.040	.130	.023	.194	.620	.116
13.0 - 14.0	76.1	71.2	83.4	.040	.130	.030	.208	.701	.138
14.0 - 15.0	75.1	70.2	82.4	.055	.136	.030	.257	.726	.148
15.0 - 16.0	74.1	69.2	81.4	.076	.140	.030	.326	.760	.168
16.0 - 17.0	73.1	68.2	80.4	.091	.140	.030	.406	.772	.175
17.0 - 18.0	72.1	67.2	79.4	.117	.140	.030	.508	.788	.180
18.0 - 19.0	71.1	66.2	78.4	.130	.140	.030	.560	.812	.190
19.0 - 20.0	70.1	65.2	77.4	.130	.144	.031	.626	.841	.221
20.0 - 21.0	69.1	64.2	76.4	.134	.150	.040	.716	.885	.263
21.0 - 22.0	68.1	63.2	75.4	.140	.150	.046	.774	.933	.321
22.0 - 23.0	67.1	62.2	74.4	.140	.150	.065	.802	.982	.459
23.0 - 24.0	66.1	61.2	73.4	.150	.150	.103	.841	1.018	.619
24.0 - 25.0	65.1	60.2	72.4	.150	.150	.120	.879	1.032	.699
25.0 - 26.0	64.1	59.2	71.4	.150	.157	.121	.916	1.047	.711
26.0 - 27.0	63.1	58.2	70.4	.150	.160	.130	.958	1.050	.720
27.0 - 28.0	62.1	57.2	69.4	.150	.163	.130	.961	1.053	.741
28.0 - 29.0	61.1	56.2	68.4	.150	.170	.130	1.008	1.071	.763
29.0 - 30.0	60.1	55.2	67.4	.150	.170	.130	1.017	1.107	.790
30.0 - 31.0	59.1	54.2	66.4	.150	.170	.133	1.031	1.128	.813
31.0 - 32.0	58.1	53.2	65.4	.152	.170	.140	1.042	1.157	.879
32.0 - 33.0	57.1	52.2	64.4	.170	.170	.140	1.062	1.170	.912
33.0 - 34.0	56.1	51.2	63.4	.170	.170	.149	1.095	1.172	.944
34.0 - 35.0	55.1	50.2	62.4	.170	.170	.150	1.114	1.187	.974
35.0 - 36.0	54.1	49.2	61.4	.170	.172	.150	1.126	1.201	1.002
36.0 - 37.0	53.1	48.2	60.4	.170	.180	.150	1.135	1.218	1.048
37.0 - 38.0	52.1	47.2	59.4	.170	.180	.153	1.146	1.237	1.077
38.0 - 39.0	51.1	46.2	58.4	.170	.189	.160	1.156	1.269	1.090
39.0 - 40.0	50.1	45.2	57.4	.170	.190	.160	1.174	1.297	1.090
40.0 - 41.0	49.1	44.2	56.4	.170	.190	.160	1.200	1.316	1.099
41.0 - 42.0	48.1	43.2	55.4	.170	.190	.160	1.220	1.337	1.100
42.0 - 43.0	47.1	42.2	54.4	.170	.199	.160	1.247	1.374	1.108
43.0 - 44.0	46.1	41.2	53.4	.180	.209	.160	1.266	1.440	1.118
44.0 - 45.0	45.1	40.2	52.4	.180	.216	.168	1.285	1.487	1.155
45.0 - 46.0	44.1	39.2	51.4	.188	.222	.170	1.330	1.559	1.160

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SEASONAL ENERGY REQUIREMENTS

REGION: HAWAII
SUB-REGION: HAWAII
UTILITY: HELC

SHEET 3 OF 4

CONTRACT NO DACW72 78 C 0013

DATE: MARCH 1980

EXHIBIT XII-3

HAWAII CITIZENS UTILITIES COMPANY-KAUAI ELECTRIC DIVISION

YEAR: 1985

WEEKLY LOAD FACTOR: OFF-SEASON 58.9
SUMMER 67.9
WINTER 60.1

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	78.1	96.4	87.2	.018	.010	.010	.019	.010	.017
1.0 - 2.0	77.1	95.4	86.2	.020	.010	.010	.051	.010	.020
2.0 - 3.0	76.1	94.4	85.2	.020	.010	.010	.085	.010	.034
3.0 - 4.0	75.1	93.4	84.2	.020	.010	.010	.124	.010	.056
4.0 - 5.0	74.1	92.4	83.2	.020	.010	.010	.140	.010	.070
5.0 - 6.0	73.1	91.4	82.2	.020	.010	.011	.181	.010	.081
6.0 - 7.0	72.1	90.4	81.2	.031	.010	.020	.238	.010	.090
7.0 - 8.0	71.1	89.4	80.2	.040	.010	.026	.301	.014	.109
8.0 - 9.0	70.1	88.4	79.2	.040	.010	.030	.380	.022	.140
9.0 - 10.0	69.1	87.4	78.2	.046	.010	.030	.456	.045	.150
10.0 - 11.0	68.1	86.4	77.2	.061	.020	.030	.531	.060	.164
11.0 - 12.0	67.1	85.4	76.2	.070	.020	.038	.641	.062	.191
12.0 - 13.0	66.1	84.4	75.2	.079	.020	.044	.703	.078	.223
13.0 - 14.0	65.1	83.4	74.2	.085	.020	.052	.734	.120	.236
14.0 - 15.0	64.1	82.4	73.2	.102	.020	.072	.771	.162	.285
15.0 - 16.0	63.1	81.4	72.2	.120	.034	.090	.815	.295	.351
16.0 - 17.0	62.1	80.4	71.2	.120	.070	.101	.846	.438	.436
17.0 - 18.0	61.1	79.4	70.2	.129	.084	.114	.874	.543	.517
18.0 - 19.0	60.1	78.4	69.2	.130	.106	.120	.905	.641	.593
19.0 - 20.0	59.1	77.4	68.2	.148	.130	.129	.948	.692	.654
20.0 - 21.0	58.1	76.4	67.2	.150	.130	.130	.978	.714	.699
21.0 - 22.0	57.1	75.4	66.2	.150	.130	.130	.995	.736	.742
22.0 - 23.0	56.1	74.4	65.2	.150	.130	.130	1.009	.766	.773
23.0 - 24.0	55.1	73.4	64.2	.150	.130	.130	1.018	.799	.795
24.0 - 25.0	54.1	72.4	63.2	.150	.136	.133	1.038	.841	.841
25.0 - 26.0	53.1	71.4	62.2	.151	.140	.150	1.084	.871	.877
26.0 - 27.0	52.1	70.4	61.2	.160	.140	.150	1.128	.888	.901
27.0 - 28.0	51.1	69.4	60.2	.160	.140	.154	1.156	.903	.933
28.0 - 29.0	50.1	68.4	59.2	.160	.140	.160	1.160	.910	.955
29.0 - 30.0	49.1	67.4	58.2	.160	.146	.160	1.160	.919	.966
30.0 - 31.0	48.1	66.4	57.2	.170	.150	.160	1.170	.948	.971
31.0 - 32.0	47.1	65.4	56.2	.170	.150	.160	1.181	.965	.988
32.0 - 33.0	46.1	64.4	55.2	.180	.150	.160	1.205	.984	1.009
33.0 - 34.0	45.1	63.4	54.2	.190	.150	.160	1.250	1.014	1.022
34.0 - 35.0	44.1	62.4	53.2	.190	.150	.160	1.268	1.033	1.059
35.0 - 36.0	43.1	61.4	52.2	.194	.151	.161	1.314	1.074	1.092
36.0 - 37.0	42.1	60.4	51.2	.200	.160	.170	1.320	1.105	1.112
37.0 - 38.0	41.1	59.4	50.2	.200	.169	.170	1.349	1.126	1.134
38.0 - 39.0	40.1	58.4	49.2	.200	.170	.170	1.391	1.149	1.175
39.0 - 40.0	39.1	57.4	48.2	.215	.170	.170	1.473	1.166	1.180
40.0 - 41.0	38.1	56.4	47.2	.237	.170	.170	1.598	1.180	1.192
41.0 - 42.0	37.1	55.4	46.2	.240	.170	.178	1.642	1.185	1.232
42.0 - 43.0	36.1	54.4	45.2	.240	.170	.186	1.676	1.209	1.272
43.0 - 44.0	35.1	53.4	44.2	.240	.170	.190	1.680	1.212	1.280
44.0 - 45.0	34.1	52.4	43.2	.240	.170	.190	1.680	1.238	1.301
45.0 - 46.0	33.1	51.4	42.2	.240	.170	.190	1.680	1.262	1.344

HARZA ENGINEERING COMPANY
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SEASONAL ENERGY REQUIREMENTS

REGION: HAWAII
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UTILITY: CIUC

CONTRACT NO. DACW72-78-C-0013
DATE MARCH 1980

EXHIBIT XII-3

APPENDIX A

LOAD CURVE ANALYSIS FOR ESTIMATING POWER AND ENERGY REQUIREMENTS FROM HYDROELECTRIC PLANTS

LIST OF EXHIBITS

LOAD CURVE ANALYSIS FOR ESTIMATING POWER AND ENERGY REQUIREMENTS FROM HYDROELECTRIC PLANTS

The utilization of hydroelectric power that is to be added to an existing electric utility system depends upon the characteristics of system generation, characteristics of system load, and the characteristics of the hydropower itself. This appendix discusses briefly the interrelationship of the three subjects and the method for evaluating dependable, or effective capacity of hydroelectric plants.

System Generation Characteristics

The electric utility system in the United States generates its power and energy primarily from thermal generating stations. Hydroelectric power and energy are used variously for base load, intermediate or peaking purposes, or a combination of all.

The distribution of generating resources between thermal and hydropower varies between different parts of the country. A group of illustrations can be cited. In the Pacific Northwest, hydropower is dominant, providing base, intermediate and peaking operation. However, development of the hydroelectric energy resource is nearing its limit under present economic and environmental constraints and large thermal plants are being installed or planned for future load growth. As a result, some hydroelectric energy will be transferred from base to intermediate or peaking. Additional hydro units are being considered or installed at existing plants to provide for peaking operation rather than adding to energy production. In California, thermal generation is the major component although hydropower is important, providing peaking power and energy and fuel-saving energy. The TVA and Southern Company areas in the South can be described in the same general terms as California. In Florida, hydropower is almost non existent and thermal supplies the load. Variations between the extremes exist throughout the remainder of the country.

In general, all thermal power functions most efficiently if load can be maintained continuously within a narrow range. In contrast, hydropower can produce efficiently under a wide range of loads. When both thermal and hydro are in a system the thermal power is used for base load and hydropower for peak loads unless there are special considerations preventing such use. This generalization usually applies, although very high fuel cost for some types of thermal generation reduces their hours of operation.

Thermal Generating Characteristics

There are variations between thermal plants in terms of fuel used, type of heat cycle, output range, and heat rate. In regions where oil or natural gas have been the most economical fuels, thermal base units which have reasonably low heat rates operate over wide ranges of load. Thermal peaking units, with higher heat rates, operate for short periods to provide for exceptionally high load demands. Such high load demands usually are of short duration, or are to compensate for emergency outages of base units. Some areas using oil fuel have hydropower for peaking. In general, oil-fired units have relatively high natural suitability for supplying varying loads and are well suited to utilizing fuel-saving energy from hydro. Even so, oil-fired steam units working at low temperatures and pressures are more suitable for varying loads than are the more efficient high-temperature, high-pressure units.

Coal-fired and nuclear units are less suited to supplying varying loads, although their relative availability is a function of steam pressure and temperature. High-temperature, high-pressure coal-fired units, which have the lowest heat rates, are most efficient and have their highest availability and efficiency when operated at constant or nearly constant load. Nuclear units can serve varying loads but in so doing waste a considerable amount of heat to the condenser. The low fuel cost of nuclear units and the system of charges for nuclear fuel make constant full-load operation most desirable.

In areas supplied primarily by coal-fired or nuclear units, peaking power is supplied variously by conventional hydropower, pumped storage, low-temperature low-pressure peaking steam, and combustion turbines.

Units operating at intermediate temperatures and heat rates are used in many systems for seasonal loads and for the parts of daily or weekly loads which are intermediate between high-load-factor base and low-load factor peaking. Such units are classified as "intermediate units". Usually they burn oil, although some systems use cycling coal-fired units for the purpose. Intermediate units can respond to load changes more rapidly than can base units and less rapidly than can true peaking units.

Installation and Operation Schedules

The electric load in the United States is served by a large number of utility companies and governmental agencies, ranging in size from a

few thousand kilowatts to millions of kilowatts. Generally, the individual companies are combined into larger groups by interconnections, coordinated scheduling of new generating capacity, coordinated scheduling of maintenance outages, and coordinated operation to obtain maximum economy.

In such large groupings of systems, maintenance schedules and schedules of unit operation from hour-to-hour are based on forecasts of load, availability of water for hydro generation, and characteristics of units or plants. The customers never act exactly according to forecasts so that reserve generating capacity must be available for instant operation when demands exceed forecasts. Reserve generating capacity also is needed to provide replacement for units that cannot operate because of scheduled maintenance outages and unscheduled emergency outages. In the resultant scheduling of unit operation, priority is given to utilizing the lowest-cost energy in such manner as to produce maximum economy. This means assigning to peak load hours the limited-energy capacity with the lowest incremental generating cost in such manner as to use all of the limited energy available and at the same time prevent as much as possible any operation of higher-cost energy sources. The assignment of units is complicated by the relative adaptabilities of both thermal units and hydrounits to variable load operation.

In planning new units, existing units are considered to be utilized up to their capability in the most economical manner. If a proposed new unit has lower operating cost than an existing unit and sufficient energy to deliver its capacity as needed, the new unit will be assigned to the highest load-factor operation. If a new unit has lower operating cost than an existing unit but has available a limited amount of energy, which means it delivers its capacity only for limited periods, the new unit will be used as advantageously as possible during peak load hours. Under either of the two foregoing circumstances, older units with higher operating cost are operated to fill voids in the load requirement that cannot be supplied by units having lower operating costs.

If an existing unit and a proposed new unit have equal operating costs, then the existing unit is considered to be fully utilized and the new unit fills future expected vacancies in the energy supply. If one low-cost unit has in effect unlimited energy supply (which applies to thermal units) and another low-cost unit has limited energy supply (which usually applies to hydropower units), the planned loading utilizes the limited energy to obtain maximum economy.

Thus, in systems already having some hydropower and a large amount of thermal power, hydropower is assigned as close as possible to the maximum load hours so that its capacity will be utilized on-peak. A hydropower plant with large capacity and small energy will be at or near the peak of the load curve; a plant with less capacity relative to its energy supply will be in a lower position in supplying the load curve.

If there is more hydroenergy in a system than is needed to supply peak loads, or if for various reasons the hydroenergy cannot be used during peak load hours, then hydroenergy will be utilized in other hours to produce maximum savings in thermal costs as much as possible. Hydroenergy always costs less to produce than thermal energy and usually hydro energy can produce savings at any hour of the day. However, such energy usually does not prevent installation of alternative sources of generation and so does not receive capacity credit. In rare situations, hydroenergy production during the lowest load hours can actually cause high temperature coal-fired units to burn oil rather than coal. However, this problem can be identified readily and measures can be taken to avoid the problem.

System Load Characteristics

Load and available hydroelectric energy vary throughout the year and from year-to-year. In general, there are three major load seasons, the summer peak, the winter peak, and the intermediate spring and autumn seasons. The spring and autumn seasons are less demanding than peak seasons from a capacity and energy viewpoint. The autumn and spring seasons have similar load characteristics and for analysis can be considered as a single group, referred to in this appendix as the "off-season".

The summer and winter peaks are affected by climate. In many parts of the country, air-conditioning is a major load and in many areas is so dominant that the summer peak is also the annual peak. In other parts of the country electric heating is a major load and is so dominant that the winter peak is the annual peak. The off-season has loads less than both summer and winter but because of less effects of temperature on load, the off-season tends to have higher load factors.

Characteristics of Hydropower

Power and energy produced by hydropower plants are subject to large variations from year-to-year and from season-to-season within a

year. It is very unusual for a hydropower plant to be able to operate at constant load because of variation in water supply from day-to-day. When water supply varies seasonally it is necessary to analyze the coincidence between periods of maximum energy and power demands and periods of maximum water availability. Usually the two will not coincide naturally, although they might be made to coincide if there is sufficient reservoir storage to permit seasonal retiming of the hydroelectric energy.

Electrical load on a system varies between hours of the day, between days of the week, and between seasons of the year. In any one day, the maximum load may be as much as 3 times the minimum load for that day; in any one year, the ratio of maximum and to minimum load may be as much as 5. Load is larger during daytime and early evening hours on days of normal commercial activity, Monday through Friday, than it is during corresponding hours on Saturdays, Sundays, and holidays. On any day, the smallest load occurs between midnight and 6 AM.

A hydropower plant usually will be installed so that its turbine discharge capacity in the normal operating head range will be a multiple of the mean natural stream discharge at the plant site. Frequently the multiple is in the range 2 to 3. If there is this much turbine discharge capacity, it may be 20 or more times as large as the minimum natural discharge of the stream, but still be much less than the maximum natural discharge. The plant usually will contain several turbines, so that operation can be reasonably efficient over discharges varying from small to large.

When stream discharge equals or exceeds turbine discharge capacity, which usually occurs a relatively small percentage of the time, the hydropower plant will produce power continuously at the rate corresponding to turbine discharge capacity. When streamflow is less than turbine discharge capacity, there are several operating options available.

One option would be to discharge streamflow through the turbines at the same rate as water inflow into the pond above the dam. Such operation will produce energy continually day and night regardless of need. When streamflow is small, it is probable that one turbine will be operating alone at low efficiency. If the power system is supplied mostly by thermal generating units, whether nuclear, coal-fired steam, oil-fired steam, gas-fired steam, oil-fired combustion turbine, gas-fired combustion turbine, oil-fired diesel, or a combined cycle using

combustion turbine and steam, fired by oil or gas, thermal plants must accommodate the load variations if hydro in the system is operated to follow streamflow.

The result is wasteful thermal operation. Heat use by thermal plants has three main components. One is to produce useful energy; the second is to maintain the equipment at operating temperature, and the third is in unavoidable heat losses in the stack and in thermodynamic processes. The second and third heat uses are non productive. A thermal plant at constant load minimizes the second heat use. A thermal plant at constant load at point of maximum efficiency minimizes the second and third heat uses. A thermal plant operating under variable load increases the second and third heat uses, and as a result reduces the first heat use and operates at lower efficiency than it would otherwise. As the ratio of peak thermal load to minimum thermal load increases, thermal efficiency lowers and operating cost per kilowatt-hour increases.

If a hydropower plant is in a predominantly thermal system and is operated to follow streamflow, it contributes little to overall system economy. The hydro operation will deduct a substantially equal amount from both the daily maximum and daily minimum thermal loads. By so operating, the hydropower increases the ratio of thermal maximum load to thermal minimum load, and so reduces overall thermal efficiency. When thermal efficiency is reduced, thermal energy is wasted and the hydro energy contributing to the waste loses value.

A second operating option for the hydropower when streamflow is less than turbine discharge capacity is to vary the discharge from hour-to-hour in an effort to provide generation when it will contribute most to obtaining thermal economy. From the viewpoint of conserving thermal energy, the ideal operating time for the hydropower is daily during the hours of above-average load. Such operation may or may not be possible, depending upon such limitations as storage availability in the pond upstream from the dam and minimum flow, or constant flow, requirements for environmental reasons in the stream channel downstream from the dam.

The second operating option also is dependent upon the generating resources available before the particular hydropower plant is completed. In general, it is an economic principle that the first plant in time is first in receiving credit for producing economic return. This obviously is a correct principle, since a utility will operate units it

has as advantageously as possible before it invests in additional units.

Evaluating Hydropower Characteristics

Meeting Load Requirements

A factor in assessing the usefulness of a new hydropower plant, once its position relative to older hydropower plants in supplying load is established, is availability of energy to meet system load requirements. If there is one hour in the week in which system load is at its maximum, hydropower can be credited with supplying the capacity needed if it has sufficient water available to supply the necessary power for the hour. If the energy available from the plant is less than is needed for that one hour, then credit to the hydropower has to be reduced to what it can supply for the hour.

If the new hydropower can supply the load needed for the one hour, but a pre-existing hydropower plant can do the same, the new plant has to go into the load curve "below" the older one, or in other words, supply load for a longer period. If the lower position requires more energy for a given amount of power, the new hydropower may have to be given less credit for power, or capacity, in accordance with the power available from the energy for the available time required.

Division of Prior Hydropower Plants. Exhibit A-1 is prepared to aid in determining the position in the load curve of pre-existing hydroelectric plants. The exhibit presents a tabulation of the distribution of hydropower by states into operating classifications. Two classification systems are shown, both representing approximations based on applying experience and judgment to available data.

The first classification system is based on the operating function of hydropower in a predominantly thermal system considering the utilization of the capacity and energy of hydropower in economy operation of the system. The second classification system describes hydropower in terms of thermal generating capacity producing equivalent power and energy.

The operating function classification applies to the use of hydropower in the daily load dispatch. The base component refers to the capacity that must be operating 24 hours per day for one of the following reasons:

1. Environmental restrictions requiring a minimum discharge from a hydroplant.

2. Lack of pondage at a hydroplant sufficient to permit transferring release of water from off peak hours to on peak hours.

A hydroplant lacking pondage to transfer water release from off-peak hours to on peak hours will produce capacity and energy that will be used in the base portion of the load curve regardless of streamflow. Because of variations in streamflow, the dependability of the generation varies from year-to-year and between seasons of the year, so that even though the generation must be produced for 24 hours per day, part of it may not be predictable, and the unpredictable part probably will not be suitable for classification as "base." The plant output may be designated as partly base and partly interruptible or fuel-saving in any week depending upon the extent to which the power system operators can rely on it. If a storm causes a sudden flow increase during a week, the portion of the generation above the predicted amount will be utilized but it will be classified operationally as interruptible or fuel-saving.

If a hyrdopower plant has sufficient pondage to transfer release of water from off peak hours to on peak hours, and sufficient generating capacity to utilize the water during on peak hours, the generation so made available may be classified as "dependable peaking". The amount of generation available will vary from week-to-week and from year-to-year. To the extent the system operators can utilize the generation, to meet particular portions of the load and can predict availability of the generation, the output will be classified as "dependable peaking". If additional and unpredicted flow during a week provides additional capacity or energy, the additional amounts will be used during on peak hours as much as possible but will be interruptible or fuel-saving.

The differentiation of generation between base, dependable peaking, and interruptible or fuel-saving as presented in Exhibit A-1 involves diverse hydrologic conditions and ability to utilize water for generation at numerous sites. At any location, hydrologic conditions are altered by storage reservoirs providing seasonal flow regulation. Some reservoirs have much more seasonal flow regulation capability than others. The designation of capacity also depends upon the characteristics of loads to be served and the portion of system load considered to be supplied by hydropower. It must be emphasized that each electric system, watershed, and powerplant has it own characteristics.

The designation of hydropower by equivalent thermal classification is based entirely on energy requirement for a given block of load and represents more nearly the way generation would be operated in an all-hydro system or an all-thermal system than in a mixed-thermal hydropower system predominantly thermal.

Under this system, base represents round-the-clock generation, intermediate generation represents a horizontal portion of load across the portion of the load curve between the base and the top part of the daily peaks, and peaking generation represents a horizontal portion of the load curve across the top part of the daily peaks.

Comparison of the classification of generation by operating function with the equivalent thermal classification on Exhibit A-1 shows that the percentage for dependable peaking operation usually is close to the percentage for intermediate equivalent thermal operation. Likewise, the percentage for interruptible or fuel-saving operation is close to the percentage for peaking equivalent thermal operation. The percentage similarities between what appear at first glance to be dissimilar items arise from the energy availabilities and requirements in the different classifications.

Exhibit A-1 reflects the relative percentage of hydro generation out of the total in the areas stated and the overall characteristics of the hydroplants relative to the loads. The table illustrates that the term "peaking" can have different meanings dependent upon the basis for defining the term.

Meeting Reserve Capacity

An additional factor in evaluating hydropower capacity is maintenance of generating reserves. Reserves provide for unexpectedly large loads (such as may result from extremely hot or cold weather), unexpected breakdown and outage of generating units, and scheduled outage of generating units. Scheduled outages are planned to be outside normal peak-load months as much as possible, but in large, modern systems it is necessary that there be scheduled outages the year round.

Thus in any month, hydropower should be evaluated considering the system conditions prevailing during that month. If loads are well below the annual maximum but a large number of units are scheduled to be out-of-service for maintenance, hydropower may be very useful to the

system, especially if streamflows normally are large during the period. A hydropower plant in such a month may have a large dependable capacity and corresponding value to the system, and if so, it should be so credited.

Under such conditions, a hydropower plant may have a different dependable capacity each month. For economic evaluation, capacity credit for hydropower should be assigned on a case-by-case basis depending on system load characteristics and requirements, and specific generating characteristics of the system. For a large predominantly thermal system, an appropriate method for preliminary evaluation of the annual dependable capacity would be the average of the monthly dependable capacities. However, even in the early stage the seasonal timing of hydro availability should be compared to the annual load pattern of the system to insure that hydroenergy is available when it is needed.

There also is the question of short-term reserve capacity. Thermal units respond less rapidly to load change than do hydropower units. If during an emergency, hydropower can respond to meet unscheduled outages and maintain load for even a few minutes while thermal unit loads are increased or power receipt through interconnection is accomplished, then hydropower should receive credit for emergency reserve value. Such value is obtainable, however, only if environmental conditions permit rapid increase and reduction in plant discharges.

In view of the foregoing, evaluating the dependable capacity of a new hydropower plant is complex. Among the questions to be answered are:

1. Can the new hydropower plant fluctuate discharge to meet the system load requirements?

2. What plants supply base load requirements? What are their characteristics?

3. What plants supply peaking or intermediate load requirements? What are their characteristics?

4. At what position in the load curve can the new hydropower plant supply generating capacity and energy?

5. How do the positions of the new hydropower plant throughout the year in the load curve fit with load requirements, reserves, and scheduled maintenance outages?

The usefulness of new hydropower plants to the Nation will depend upon their characteristics relative to the foregoing factors. However, in preliminary studies it is not warranted to consider the factors in detail, yet they cannot be ignored. The traditional computation of dependable capacity based on a minimum streamflow or a low streamflow near minimum may not provide adequate economic credit to a new hydropower plant, particularly if its flow can be regulated hourly by use of pondage or other upstream means of flow regulation. Conversely, a hydropower plant having a particular number of kilowatts installed to obtain energy may be over rated if it is credited with that amount of dependable capacity. In subsequent stages of the hydroelectric evaluation process, the factors can be considered in increasing detail as the studies leading to plant authorization are approached.

The studies, whether preliminary or advanced, can be based on the same load curve data. As mentioned before, there are three major load seasons each year - summer, winter, and intermediate, or "off season", in spring and autumn. Load curve data which can be used for any future year, and which provide means for inserting a new hydropower plant into any position in the load curve, provide ideal tools for hydropower plant evaluation at any point in the study.

Future Projections

Assessment of undeveloped hydropower resources requires a reasonably firm basis for evaluating seasonal and annual mean dependable capacities with respect to the regional system loads. Seasonal load curves provide the basic data for evaluating hydropower plants. The procedure for estimating future seasonal load curves is described herein.

Seasonal Load Curves. The data required to analyze seasonal variations in load characteristics can be found in the utilities annual report to FERC, Form 12, Schedules 14 and 15. FERC requires that a utility report hourly load curves for the first week in April, August, and December. August is representative of the summer peak demand, although the summer peak may occur in either July or August. December represents the winter peak demand. Occasionally, the winter peak occurs in January rather than December; however, there is little difference in load variation between the two months. April is representative of the remainder, which is designated as the off-season.

The analysis also requires the maximum hourly load reported for the year. The maximum hourly load does not necessarily occur during any of the three reported weeks.

Each of the three seasonal hourly load curves for a week in a region or subregion are reduced to dimensionless form by dividing the hourly loads by the annual peak load. However, because the annual peak does not always occur in one of these three weeks, the weekly load curve which corresponds to the annual peak season must be adjusted upwards. This is done by multiplying by the dimensionless loads in this week by the ratio of the annual peak to the largest load of the week. Relating all loads to the annual peak aids in assessing seasonal needs for capacity and energy, and provides a fixed basis for evaluating a given hydropower installation throughout a particular year.

Effect of Load Growth on Load Shape. Past experience has been that the overall shape of a load curve is not changed appreciably by load growth, assuming no change in system load factor. Weather, business days, weekends, holidays, and relative industrial activity change load shapes from day-to-day within any one week and on the corresponding day from year-to-year. However, the length of daily peak periods and off-peak periods remains essentially unchanged and the relative magnitudes of on-peak and off-peak loads throughout a week or season remain approximately proportional.

Effect of Load Factor on Load Shape. Devices and systems now under consideration could change the shape of load curves to the extent they are adopted. Devices and systems such as time-of-day pricing, load control, electric automobiles, and heat storage systems are expected to increase load factor. Offsetting reductions in load factor may result from use of other energy sources such as wind, solar, or co generation. The final effect of these devices and systems, individually and collectively, on load shape is speculative.

In practice, it can be expected that the bulk of human activity, and resultant use of electric energy, will remain during the daytime and early evening hours. The increase in loads for any projected increase in load factor, therefore, should be in the daytime and early evening hours rather than in the peak hour itself. If load factor is increased, the peak load in fact will be reduced and loads in other hours will be more nearly equal to the peak. However, since in the dimensionless load analysis system, the peak load by definition is the largest and is expected to remain so, the loads outside the peak will increase in relative amount.

Procedure for Adjusting Loads

A procedure for adjusting weekly load curves to reflect changes in load factor as discussed in the previous section has been developed as part of this study. The procedure is based on the assumption that no new major energy demand will occur during the nightime. If demands such as the needs for charging electric vehicles batteries, or for energy storage would increase significantly, the load patterns would change differently. Furthermore, if the economic incentives are such that some commercial and industrial loads are transferred to the nightime, this would also affect the load curves. But under present conditions, these changes, if they occur, are not expected to have a significant impact before the 1990's.

The procedure involves adjustments of the hourly loads on either side of the daily peak loads. The adjustments are somewhat tedious to perform and as a result, a computer program has been written to modify the load curve. The program, which also generates energy tables corresponding to the seasonal load curves, is described later in this appendix.

The step-by-step procedure for adjusting the three representative weekly load curves (summer, winter, and off-season) to correspond to increased load factor is as follows:

1. Compute hourly loads to three decimal places, dividing reported hourly loads by the annual peak load. If the largest load available in the weekly load curves being considered is less than the annual peak, multiply all loads of the seasonal week representative of the annual peak by the ratio of the annual peak to the highest peak of the week.

2. Rank the loads of each day in order of size, calling the largest "1" and the smallest "24".

3. Select a load factor increase and compute its effects <u>each</u> day on an hourly basis.

4. For first trial, select the loads in the 12 hours of the day having highest loads other than the peak hour (loads 2 to 13, inclusive). (Refer to Exhibit A-2).

5. Increase hourly desired loads 2 through 13 by an amount equal to twice the load factor increase.

6. Compare the loads as increased with the peak load. Arbitrarily restrict loads as increased to a number 0.2% (0.002), less than the peak load (so that the peak remains the peak).

7. Accumulate the amounts which must be deducted from the hourly loads to prevent those loads from exceeding the amount in 6, above.

8. Distribute the excess in order of size of load among the next highest loads outside of the 13 hours (starting with load 14), at the rate per hour of twice the increase in load factor until the excess is exhausted. The load increase in the last hour considered (which may be load 14 or a larger-numbered load) usually will be less than the increase in other hours of larger load.

As illustration, (refer to Exhibit A-2), if a 2% increase in load factor is desired, the increase in the 12 hourly loads next larger than the peak would be twice 2%, or 0.04. If on the day in question peak load was 0.876 times annual peak load, the largest load in other hours would be 0.876 minus 0.002, or 0.874, so that the existing peak remains the peak (refer to 6. above). Thus, if there were hourly loads during the same day 0.835 or more times as large as the annual peak load, those loads would be increased so that they would be not larger than 0.874 times annual peak load. The accumulated amounts by which the increase in such loads was less than 0.02 per hour would be assigned first to the 14th largest load, limiting the load increase in any hour to 0.04. If the accumulated amount would be 0.063, for illustration, the load in hour 14 would be increased by 0.04 and in hour 15 would be increased by 0.023.

Adjustment of a load curve for load factor reduction would be performed similarly, except that hourly loads would be reduced and there would be no need to limit the change in any hour. The suggested procedure is to reduce the loads in hours 2 to 5 by the desired load factor change and in hours 6 to 14 by twice the desired load change.

As stated earlier, a computer planning model has been developed which follows the foregoing process of load factor adjustment. Exhibits A-3 through A-5 were produced by computer. Exhibit A-3 presents a daily load curve for a representative utility in MARCA in dimensionless form derived from a 1977 load curve without load factor adjustment. Exhibit A-4 presents the daily load curve in dimensionless

form for the same region and day if the load factor is increased by 2%. Exhibit A-5 presents the load curve in dimensionless form for the same region and day with the load factor reduced by 1%.

A detailed description of the input data required for the computer program is presented at the end of this appendix. The computer program performs the dual function of first adjusting the hourly load curve and secondly computing the energy required at various positions under the load curve. The tabulation of required energy to fill various positions under the load curve is presented in Exhibits A-6, A-7, and A-8. These exhibits respectively correspond to the 1977 load curve with no adjustments, the 1977 load curve adjusted for a 2% increase in load factor and the 1977 load curve adjusted for a 1% decrease in load factor. Use of the energy tables as presented in Exhibits 6, 7, and 8 is discussed in the following section.

Plant Evaluation

The energy tables referred to in the previous section may be used to compute consistent seasonal dependable capacities for any proposed hydropower plant. The procedure involves the following basic steps, which are explained in more detail in the following paragraphs:

1. Select the region or subregion to be analyzed.

2. Divide the months of the year into summer, winter, and off-season in accordance with the part of the country. (See Exhibit A-9).

3. Select the year for which proposed new hydropower plants are to be evaluated for dependable capacity.

4. Investigate the amount of currently existing hydroelectric installed capacity plus hydroelectric installed capacity under construction but committed to enter service in the region or subregion for the year selected.

5. Compute the annual peak load in the region or subregion for the year of study using Projection I, Projection II, Projection III, median projection, or a future revised projection as desired.

6. Designate the annual peak load as unity and compute all other loads as decimal ratios to the annual peak load.

7. Divide existing hydropower between peaking and base load operation as appropriate to its energy capability, capacity capability and storage. (Refer to Exhibit A-1).

8. Compute the ratio of the sum of existing and committed hydropower peaking capacity to annual peak load for the year selected.

9. Subtract the ratio computed in 8 above from the peak load computed in 6 in each of the summer, winter, and off-seasons to obtain the top position of new hydropower under the load curve.

10. Compute the energy available each month from the new hydropower plants under consideration. The original number will be in kilowatt hours. Convert kilowatt hours to hours of annual peak load. Flow data from the U.S. Geological Survey or similar sources and the plant head will provide the basic data for computing monthly energy.

11. Select the system load factor to be used, whether existing, increased by a percentage, or existing reduced by a percentage.

12. Use or compute the table of daily and weekly energy requirements for 1% of the annual peak and in various positions under the daily and weekly load curves. The energy requirements will be computed in terms of hours of annual peak load. (Refer to Exhibits A-6, A-7, and A-8).

13. Compute for each month the amount of capacity that can be provided by the hydroenergy available from new hydropower plants under consideration, using the seasonal load curve appropriate to the month. The top of the new hydropower capacity block will be at the base of the existing and committed hydropower peaking capacity block. All capacity figures will be in terms of annual peak load and all energy quantities will be in terms of hours of annual peak load.

Further discussion of the foregoing procedural steps follows:

a. Regional or subregional selection will depend upon the location of the new proposed hydroelectric plant or plants

under consideration and the area in which the new hydropower output will be marketed.

b. Exhibit A-9 lists the months applicable to representative seasonal load curves in various parts of the country.

c. The year selected should be some future year in which the hydropower plant could be expected to be completed reasonably, allowing for licensing or other authorization, design, and construction. Later years might be considered also, since energy requirements for particular blocks of capacity tend to reduce as load increases, which will increase future dependable capacities of hydropower plants if they are not restricted for environmenal reasons from being operated to produce the dependable capacities.

d. The data for loads and plant capabilities are readily available from the Federal Energy Regulatory Commission, reliability councils, and agencies owning and operating hydropower plants such as the Corps of Engineers, Department of the Interior, and Tennessee Valley Authority. But because of rescheduling and plan changes, in service dates of new plants and units should be rechecked annually.

e. This volume describes four projections (I, II, III, and the median). Because of rapidly changing conditions in the utility industry and in the energy supply situations, projections should be reviewed and revised not less often than once every two years.

f. Division of pre-existing hydropower into base and peaking will vary with passage of time as load grows and as the proportion of hydropower units to thermal units changes. Changes in the environmental requirements for minimum discharges through hydropower plants and variations in hydropower reservoir levels also can affect the division. In general, the divisions shown in Exhibit A-1 of pre-existing hydropower plants with base and peaking are reasonable approximations at the present time.

g. The ratio in 8 above is the amount of dependable peaking capacity computed in 6, divided by the annual peak load expressed to 3 decimal points.

h. In the month of annual peak load the top of the new hydropower block will be 1.000 less the ratio computed in 8 above. In other months the top of the new hydropower block will be the same distance below the peak load for that month as the ratio computed in 8. As an illustration, if that ratio in 8 is 0.100 and the seasonal peak load is 0.900 (in terms of annual peak load the top of the new hydropower energy block is at 0.800.

i. The energy available each month can be computed for one plant, a series of plants on the same river, or a group of plants on several adjacent rivers having similar seasonal flow distributions. Mean flows for each month are suitable for early evaluation. For later evaluations, flow larger and smaller than mean flow also can be considered. The benefits of storage or pondage should be considered. The energy is the product of effective head, discharge, and efficiency. A reasonable formula for monthly energy in kWh is:

$$\frac{QHT}{14},$$

in which

Q = Monthly mean discharge (cfs)
H = Effective head (feet)
T = Hours in month

The constant 14 allows for plant efficiency, conduit head loss, tailwater rise, and a small drawdown for pondage use. The effective utilization corresponding to the constant 14 is 84.3%. As the studies are refined, the constant may be changed. There should be a check to insure that Q does not exceed the turbine discharge capacity. There also should be a check on minimum discharge required for environmental reasons. If there is a minimum discharge requirement, the energy which the minimum discharge will produce should be considered as applying 100% of the time, which will provide one component of the plant's dependable capacity. If there is water available in addition to the minimum discharge, the additional water will provide a second component of dependable capacity. The energy provided by the minimum discharge

should be deducted from the total energy available, and the remaining energy should be noted as a separate energy block. The dependable capacities from the minimum discharge and additional discharge will be added.

j. If there are diversions from the proposed plants for fish passage facilities, irrigation or other uses, they should be deducted from the water available.

k. The load factors could be increased or reduced as described earlier.

l. The energy tabulations state the energy required daily and weekly in the three seasons to supply 1% increments of the annual peak load. These tabulations and programs for utilizing the data should be stored in the computer.

m. If the energy available from new hydropower plants is less than that needed to supply a 1% increment of load below the load computed in 9, the dependable capacity provided can be considered as (a) the ratio of energy available to energy required for 1% of the annual peak load multiplied by (b) 1% of the annual peak load. Similarly, if the top of the new hydropower block is not at a whole number percentage of the annual peak load, the fractional portion of the 1% increment remaining will be analyzed first.

n. If the energy available exceeds the amount necessary to supply 1% of the annual peak load, the excess will be carried into the next lower 1% increment and the portion of the dependable capacity computed by the same formula as in the preceding paragraphs. A series of iterations may be required to compute the number of 1% blocks to be used and the portions of the upper and lower blocks.

The dependable capacity of the new plant or plants can be evaluated, depending upon conditions, as the largest monthly dependable capacity computed or the average of 12 monthly dependable capacities.

<u>Input Data Required for Load Curve Analysis Program</u>

The Load Curve Analysis Program is used to generate dimensionless load curves and energy tables for electric power sytsems as previously

discussed in this appendix. The program can also make adjustments to the load curves and energy tables to correspond to changes in load factors. A description of the required input data is as follows:

Hourly system loads for one week, beginning with hour ending at 1 am Sunday (MW)

Hourly loads for first week of April (off-season)
Hourly loads for first week of August (summer)
Hourly loads for first week of December (winter)

Annual system peak load (MW) and season in which the annual peak occurs

Number of load factor adjustments to be considered, plant generating capacity to be considered as percent of peak load, and the year from which the hourly loads are taken.

The percent increase (or decrease-negative value) in load factor to be considered

The computer program can be used to generate load curves and energy tables for as many electric power systems as the analysis requires.

DIVISION OF PRIOR HYDROPOWER PLANTS INTO BASE, INTERMEDIATE AND PEAKING

	Portion of Installed Capacity of Hydroelectric Plants				
		Operating Function		Equivalent Thermal Classification	
Area	Base	Dependable Peaking	Inter-ruptible or Fuel-Saving	Inter-mediate	Peaking
New England	15%	35%	50%	30%	55%
New York (other than Niagara and St. Lawrence)	10%	40%	50%	40%	50%
New York - Niagara and St. Lawrence	40%	50%	10%	50%	10%
Pennsylvania, Maryland, West Virginia, Virginia	5%	45%	50%	40%	55%
North Carolina, South Carolina, Georgia	10%	60%	30%	60%	30%
Tennessee, Kentucky, Alabama	10%	70%	20%	60%	30%
Michigan, Wisconsin, Minnesota, Indiana	10%	60%	30%	40%	50%
Missouri River - South Dakota, North Dakota, Montana	70%	20%	10%	20%	10%
Arizona (including Hoover and Glen Canyon Dams)	30%	60%	10%	50%	20%
California	25%	50%	25%	30%	45%
Pacific Northwest - Oregon, Washington, Idaho, Montana	60%	30%	10%	20%	20%
Alaska	15%	80%	5%	30%	55%
Other states	0	40%	60%	40%	60%

Exhibit A-2

DIMENSIONLESS LOAD CURVES
ADJUSTMENT FOR LOAD FACTOR

One Day Shown for Illustration
Assume 2% Increase in Load FActor

Adjustment Rules

1. Apply increase in loads to 12 highest hours per day other than peak.
2. Increase hourly loads by twice the load factor increase (4% in this instance).
3. Maximum load in any hour other than peak should be 0.002 less than daily peak.
4. Apply remaining excess as 4% of next highest hours until used.

Hour Ending	Hourly Load in Terms of Annual Peak	Order of Rank	Load Factor Adjustment: 4%	Load Factor Adjustment: Limit (0.876-0.002)	Reduction of Increase	Adjusted Load Curve
1 AM	0.646		--	--		0.646
2	0.621		--	--		0.621
3	0.612		--	--		0.612
4	0.606		--	--		0.606
5	0.610		--	--		0.610
6 AM	0.628		--	--		0.628
7 AM	0.701	17	--	--		0.701
8	0.788	14 *	0.828	0.828		0.828
9	0.828	7	0.868	0.868		0.868
10	0.834	6	0.874	0.874		0.874
11 AM	0.840	5	0.880	0.874	(0.006)	0.874
12 Noon	0.826	8	0.866	0.866		0.866
1 PM	0.814	11	0.854	0.854		0.854
2	0.819	10	0.859	0.859		0.859
3	0.811	13	0.851	0.851		0.851
4	0.814	12	0.854	0.854		0.854
5	0.853	3	0.893	0.874	(0.019)	0.874
6 PM	0.876	1	--	0.876		0.876
7 PM	0.862	2	0.902	0.874	(0.028)	0.874
8	0.844	4	0.884	0.874	(0.010)	0.874
9	0.824	9	0.864	0.864		0.864
10	0.787	15 *	0.827	0.810		0.810
11 PM	0.732	16	--	--		0.732
12 Night	0.673	18	--	--		0.673
TOTAL	18.249					18.729
L.F.	0.760					0.780

*These loads are increased only because the loads in hours ending 11 am, 5 pm, 7 pm, and 8 pm cannot be increased by the full 0.040.

MARCA NEBRASKA PUBLIC POWER DISTRICT

YEAR: 1985
WEEKLY LOAD FACTOR: OFF SEASON 36.4
SUMMER 58.9
WINTER 60.7

ADJUSTED SYSTEM DIMENSIONLESS LOAD CURVES
ADJUSTED FOR -.0 PERCENT INCREASE IN LOAD FACTOR

O F F - S E A S O N

HOUR ENDING	SUNDAY AM	SUNDAY PM	MONDAY AM	MONDAY PM	TUESDAY AM	TUESDAY PM	WEDNESDAY AM	WEDNESDAY PM	THURSDAY AM	THURSDAY PM	FRIDAY AM	FRIDAY PM	SATURDAY AM	SATURDAY PM
1	.320	.382	.339	.459	.378	.449	.339	.397	.308	.381	.265	.342	.249	.329
2	.294	.368	.325	.463	.350	.439	.319	.394	.282	.387	.249	.342	.234	.328
3	.287	.369	.320	.458	.351	.428	.326	.376	.285	.368	.246	.336	.228	.319
4	.289	.361	.324	.457	.345	.422	.318	.368	.286	.365	.244	.324	.226	.324
5	.284	.369	.331	.476	.357	.420	.325	.370	.289	.364	.249	.332	.228	.326
6	.293	.388	.332	.486	.359	.434	.326	.380	.297	.376	.252	.339	.222	.340
7	.301	.400	.364	.492	.393	.436	.366	.375	.337	.374	.268	.339	.235	.338
8	.328	.432	.443	.509	.459	.463	.421	.416	.403	.393	.320	.366	.289	.374
9	.368	.419	.470	.483	.478	.441	.436	.407	.410	.386	.357	.357	.328	.367
10	.382	.416	.480	.470	.474	.430	.434	.386	.416	.368	.361	.334	.341	.339
11	.381	.384	.487	.415	.484	.397	.427	.359	.405	.342	.364	.318	.348	.321
12	.386	.347	.493	.388	.477	.357	.426	.312	.412	.294	.370	.273	.349	.282

S U M M E R

HOUR ENDING	SUNDAY AM	SUNDAY PM	MONDAY AM	MONDAY PM	TUESDAY AM	TUESDAY PM	WEDNESDAY AM	WEDNESDAY PM	THURSDAY AM	THURSDAY PM	FRIDAY AM	FRIDAY PM	SATURDAY AM	SATURDAY PM
1	.476	.599	.539	.768	.548	.701	.549	.676	.443	.597	.480	.662	.519	.628
2	.445	.628	.501	.777	.519	.733	.510	.672	.428	.597	.441	.672	.474	.626
3	.433	.647	.474	.786	.489	.726	.491	.668	.418	.593	.434	.686	.453	.641
4	.423	.666	.468	.799	.478	.763	.472	.660	.405	.606	.428	.712	.443	.634
5	.407	.696	.456	.789	.462	.780	.470	.648	.407	.616	.421	.711	.430	.656
6	.394	.726	.452	.803	.463	.809	.474	.656	.415	.622	.434	.724	.436	.659
7	.401	.748	.470	.790	.481	.802	.484	.621	.439	.619	.441	.716	.442	.661
8	.400	.718	.514	.764	.521	.766	.539	.589	.485	.601	.497	.690	.470	.632
9	.445	.702	.599	.733	.589	.745	.597	.582	.536	.584	.556	.657	.526	.603
10	.489	.734	.651	.734	.641	.745	.636	.575	.566	.598	.603	.660	.583	.597
11	.540	.678	.719	.682	.678	.684	.655	.534	.584	.564	.632	.620	.605	.572
12	.578	.584	.760	.626	.703	.609	.680	.486	.609	.518	.651	.549	.639	.516

W I N T E R

HOUR ENDING	SUNDAY AM	SUNDAY PM	MONDAY AM	MONDAY PM	TUESDAY AM	TUESDAY PM	WEDNESDAY AM	WEDNESDAY PM	THURSDAY AM	THURSDAY PM	FRIDAY AM	FRIDAY PM	SATURDAY AM	SATURDAY PM
1	.417	.493	.441	.657	.571	.652	.540	.628	.507	.686	.620	.709	.558	.592
2	.401	.473	.438	.651	.568	.632	.523	.622	.489	.681	.608	.696	.552	.572
3	.393	.461	.434	.641	.559	.628	.525	.610	.489	.674	.597	.676	.541	.554
4	.389	.450	.447	.643	.562	.628	.520	.611	.495	.687	.589	.659	.532	.543
5	.385	.470	.459	.667	.568	.659	.518	.637	.490	.703	.603	.678	.531	.563
6	.393	.541	.471	.740	.581	.722	.545	.705	.514	.778	.618	.748	.543	.649
7	.407	.553	.541	.747	.612	.719	.589	.695	.576	.783	.657	.738	.560	.656
8	.442	.541	.635	.720	.712	.694	.678	.676	.668	.765	.755	.716	.614	.636
9	.471	.534	.673	.711	.707	.672	.674	.656	.695	.753	.740	.693	.631	.605
10	.489	.516	.693	.692	.701	.654	.667	.629	.698	.718	.749	.665	.638	.586
11	.489	.505	.698	.655	.696	.630	.676	.603	.709	.709	.757	.650	.644	.570
12	.492	.453	.701	.600	.690	.579	.666	.541	.705	.652	.739	.597	.638	.534

Exhibit A-3

MARCA   NEBRASKA PUBLIC POWER DISTRICT   YEAR: 1985

WEEKLY LOAD FACTOR: OFF SEASON 38.4
SUMMER 60.9
WINTER 62.7

ADJUSTED SYSTEM DIMENSIONLESS LOAD CURVES
ADJUSTED FOR 2.0 PERCENT INCREASE IN LOAD FACTOR

O F F - S E A S O N

HOUR	SUNDAY		MONDAY		TUESDAY		WEDNESDAY		THURSDAY		FRIDAY		SATURDAY	
ENDING	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM
1	.320	.422	.339	.499	.378	.482	.350	.434	.340	.414	.296	.368	.249	.369
2	.294	.408	.325	.503	.350	.479	.319	.434	.282	.414	.249	.368	.234	.368
3	.287	.409	.320	.498	.351	.468	.326	.416	.285	.408	.246	.368	.228	.359
4	.289	.384	.324	.497	.345	.462	.318	.408	.286	.405	.244	.364	.226	.364
5	.284	.409	.331	.507	.357	.460	.325	.410	.289	.404	.249	.368	.228	.366
6	.293	.428	.332	.507	.359	.474	.326	.420	.297	.414	.252	.368	.222	.372
7	.301	.430	.364	.507	.418	.476	.406	.415	.377	.414	.308	.368	.235	.372
8	.328	.432	.483	.509	.482	.482	.434	.434	.414	.414	.360	.368	.303	.374
9	.408	.430	.507	.507	.482	.481	.436	.434	.414	.414	.368	.368	.368	.372
10	.422	.430	.507	.507	.482	.470	.434	.426	.416	.408	.368	.368	.372	.372
11	.421	.424	.507	.455	.484	.437	.434	.399	.414	.382	.368	.358	.372	.361
12	.426	.347	.507	.399	.482	.357	.434	.312	.414	.294	.370	.313	.372	.282

S U M M E R

HOUR	SUNDAY		MONDAY		TUESDAY		WEDNESDAY		THURSDAY		FRIDAY		SATURDAY	
ENDING	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM
1	.476	.639	.560	.801	.548	.741	.589	.678	.483	.620	.480	.702	.559	.659
2	.445	.668	.501	.801	.519	.773	.517	.678	.428	.620	.441	.712	.474	.659
3	.433	.687	.474	.801	.489	.766	.491	.678	.418	.620	.434	.722	.453	.659
4	.423	.706	.468	.801	.478	.803	.472	.678	.405	.620	.428	.722	.443	.659
5	.407	.736	.456	.801	.462	.807	.470	.678	.407	.620	.421	.722	.430	.659
6	.394	.746	.452	.803	.463	.809	.474	.678	.415	.622	.434	.724	.436	.659
7	.401	.748	.470	.801	.481	.807	.484	.661	.459	.620	.441	.722	.442	.661
8	.400	.746	.514	.801	.521	.806	.579	.629	.525	.620	.497	.722	.470	.659
9	.445	.742	.639	.773	.589	.785	.637	.622	.576	.620	.596	.697	.566	.643
10	.510	.746	.691	.774	.681	.785	.676	.615	.606	.620	.643	.700	.623	.637
11	.580	.718	.759	.722	.718	.724	.678	.574	.620	.604	.672	.660	.645	.612
12	.618	.624	.800	.666	.743	.618	.680	.486	.620	.558	.691	.571	.659	.555

W I N T E R

HOUR	SUNDAY		MONDAY		TUESDAY		WEDNESDAY		THURSDAY		FRIDAY		SATURDAY	
ENDING	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM
1	.417	.533	.441	.697	.571	.692	.540	.668	.507	.726	.636	.749	.598	.632
2	.401	.513	.438	.691	.568	.672	.523	.662	.489	.721	.608	.736	.552	.612
3	.393	.501	.434	.656	.559	.668	.525	.650	.489	.707	.597	.716	.541	.585
4	.389	.457	.447	.683	.562	.668	.520	.651	.495	.727	.589	.699	.532	.543
5	.385	.510	.459	.707	.568	.699	.518	.677	.490	.743	.603	.718	.531	.603
6	.393	.551	.471	.745	.581	.722	.545	.705	.514	.781	.618	.755	.543	.654
7	.407	.553	.541	.747	.648	.720	.589	.703	.576	.783	.697	.755	.600	.656
8	.442	.551	.635	.745	.720	.720	.703	.703	.668	.781	.755	.755	.654	.654
9	.511	.551	.713	.745	.720	.712	.703	.696	.735	.781	.755	.733	.654	.645
10	.529	.551	.733	.732	.720	.694	.703	.669	.738	.758	.755	.705	.654	.626
11	.529	.545	.738	.695	.720	.670	.703	.609	.749	.749	.757	.690	.654	.610
12	.532	.493	.741	.600	.720	.579	.703	.541	.745	.652	.755	.597	.654	.534

Exhibit A-4

MARCA NEBRASKA PUBLIC POWER DISTRICT

YEAR: 1985

WEEKLY LOAD FACTOR: OFF SEASON 35.4
SUMMER 57.9
WINTER 59.7

ADJUSTED SYSTEM DIMENSIONLESS LOAD CURVES
ADJUSTED FOR-1.0 PERCENT INCREASE IN LOAD FACTOR

O F F - S E A S O N

HOUR	SUNDAY		MONDAY		TUESDAY		WEDNESDAY		THURSDAY		FRIDAY		SATURDAY	
ENDING	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM
1	.320	.362	.339	.439	.378	.429	.339	.377	.308	.361	.265	.322	.249	.309
2	.294	.348	.325	.443	.350	.419	.319	.374	.282	.367	.249	.322	.234	.308
3	.287	.349	.320	.438	.351	.408	.326	.356	.285	.348	.246	.316	.228	.299
4	.289	.341	.324	.437	.345	.402	.318	.348	.286	.345	.244	.304	.226	.304
5	.284	.349	.331	.456	.357	.400	.325	.350	.289	.344	.249	.312	.228	.306
6	.293	.378	.332	.476	.359	.414	.326	.360	.297	.356	.252	.319	.222	.320
7	.301	.390	.364	.482	.393	.416	.366	.355	.337	.354	.268	.319	.235	.318
8	.328	.432	.423	.509	.439	.453	.411	.396	.393	.373	.300	.356	.289	.374
9	.348	.409	.450	.463	.468	.421	.436	.387	.400	.366	.347	.337	.308	.357
10	.362	.406	.460	.450	.464	.410	.424	.366	.416	.348	.351	.314	.331	.319
11	.361	.364	.477	.415	.484	.397	.417	.359	.395	.342	.354	.318	.338	.301
12	.366	.347	.483	.388	.467	.357	.416	.312	.402	.294	.370	.273	.339	.282

S U M M E R

HOUR	SUNDAY		MONDAY		TUESDAY		WEDNESDAY		THURSDAY		FRIDAY		SATURDAY	
ENDING	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM
1	.476	.579	.539	.748	.548	.681	.529	.666	.443	.577	.480	.642	.519	.608
2	.445	.608	.501	.757	.519	.713	.510	.662	.428	.577	.441	.652	.474	.606
3	.433	.627	.474	.776	.489	.706	.491	.658	.418	.573	.434	.666	.453	.631
4	.423	.646	.468	.789	.478	.753	.472	.650	.405	.596	.428	.702	.443	.614
5	.407	.676	.456	.779	.462	.770	.470	.628	.407	.606	.421	.701	.430	.646
6	.394	.716	.452	.803	.463	.809	.474	.636	.415	.622	.434	.724	.436	.650
7	.401	.748	.470	.780	.481	.792	.484	.601	.439	.609	.441	.706	.442	.661
8	.400	.708	.514	.744	.521	.756	.539	.569	.485	.581	.497	.680	.470	.612
9	.445	.692	.599	.713	.589	.725	.577	.562	.516	.564	.536	.637	.506	.583
10	.469	.724	.631	.714	.621	.725	.616	.555	.546	.578	.583	.640	.563	.577
11	.520	.658	.699	.662	.658	.664	.635	.534	.564	.544	.612	.600	.585	.552
12	.558	.564	.740	.606	.683	.589	.680	.486	.599	.518	.631	.549	.629	.516

W I N T E R

HOUR	SUNDAY		MONDAY		TUESDAY		WEDNESDAY		THURSDAY		FRIDAY		SATURDAY	
ENDING	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM	AM	PM
1	.417	.473	.441	.637	.571	.632	.540	.608	.507	.666	.620	.689	.558	.572
2	.401	.453	.438	.631	.568	.612	.523	.602	.489	.661	.608	.676	.552	.552
3	.393	.441	.434	.621	.559	.608	.525	.590	.489	.654	.597	.656	.541	.554
4	.389	.450	.447	.623	.562	.628	.520	.591	.495	.667	.589	.639	.532	.543
5	.385	.450	.459	.647	.568	.639	.518	.617	.490	.683	.603	.658	.531	.543
6	.393	.531	.471	.730	.581	.722	.545	.705	.514	.768	.618	.738	.543	.639
7	.407	.553	.541	.747	.612	.709	.589	.685	.576	.783	.657	.718	.540	.656
8	.442	.531	.635	.710	.702	.674	.668	.666	.668	.755	.745	.696	.594	.616
9	.451	.524	.653	.701	.697	.652	.654	.636	.675	.743	.730	.673	.611	.585
10	.469	.506	.673	.672	.691	.634	.647	.609	.678	.708	.739	.645	.628	.566
11	.469	.485	.678	.635	.676	.610	.666	.603	.689	.689	.757	.650	.634	.550
12	.472	.433	.691	.600	.670	.579	.646	.541	.685	.652	.719	.597	.628	.534

Exhibit A-5

MARCA NEBRASKA PUBLIC POWER DISTRICT

YEAR: 1985
WEEKLY LOAD FACTOR: OFF-SEASON 36.4
SUMMER 58.9
WINTER 60.7

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
***********	OFF SEASON	SUMMER	WINTER	OFF-SEASON **********	SUMMER ******	WINTER ******	OFF-SEASON **********	SUMMER ******	WINTER ******
.0 - 1.0	49.9	79.9	77.3	.010	.013	.015	.010	.018	.015
1.0 - 2.0	48.9	78.9	76.3	.016	.020	.022	.016	.041	.022
2.0 - 3.0	47.9	77.9	75.3	.049	.022	.030	.054	.068	.037
3.0 - 4.0	46.9	76.9	74.3	.078	.030	.040	.108	.088	.074
4.0 - 5.0	45.9	75.9	73.3	.103	.041	.040	.147	.117	.114
5.0 - 6.0	44.9	74.9	72.3	.137	.050	.040	.197	.140	.130
6.0 - 7.0	43.9	73.9	71.3	.143	.062	.044	.214	.161	.159
7.0 - 8.0	42.9	72.9	70.3	.150	.074	.064	.265	.189	.223
8.0 - 9.0	41.9	71.9	69.3	.150	.087	.096	.328	.230	.304
9.0 - 10.0	40.9	70.9	68.3	.155	.090	.117	.396	.272	.402
10.0 - 11.0	39.9	69.9	67.3	.160	.096	.139	.447	.300	.447
11.0 - 12.0	38.9	68.9	66.3	.160	.110	.155	.497	.328	.535
12.0 - 13.0	37.9	67.9	65.3	.168	.115	.160	.577	.357	.600
13.0 - 14.0	36.9	66.9	64.3	.170	.129	.169	.678	.411	.689
14.0 - 15.0	35.9	65.9	63.3	.174	.130	.170	.822	.456	.746
15.0 - 16.0	34.9	64.9	62.3	.180	.130	.170	.932	.534	.826
16.0 - 17.0	33.9	63.9	61.3	.180	.132	.170	1.000	.582	.870
17.0 - 18.0	32.9	62.9	60.3	.194	.140	.170	1.134	.629	.922
18.0 - 19.0	31.9	61.9	59.3	.220	.140	.170	1.253	.690	.974
19.0 - 20.0	30.9	60.9	58.3	.240	.140	.170	1.368	.737	1.013
20.0 - 21.0	29.9	59.9	57.3	.240	.150	.173	1.390	.785	1.046
21.0 - 22.0	28.9	58.9	56.3	.240	.150	.180	1.421	.877	1.093
22.0 - 23.0	27.9	57.9	55.3	.240	.160	.180	1.498	.933	1.148
23.0 - 24.0	26.9	56.9	54.3	.240	.160	.180	1.534	.978	1.191
24.0 - 25.0	25.9	55.9	53.3	.240	.160	.180	1.554	1.002	1.267
25.0 - 26.0	24.9	54.9	52.3	.240	.160	.180	1.563	1.017	1.319
26.0 - 27.0	23.9	53.9	51.3	.240	.169	.180	1.609	1.050	1.356
27.0 - 28.0	22.9	52.9	50.3	.240	.170	.194	1.630	1.093	1.385
28.0 - 29.0	21.9	51.9	49.3	.240	.172	.201	1.666	1.110	1.401
29.0 - 30.0	20.9	50.9	48.3	.240	.190	.228	1.680	1.162	1.459
30.0 - 31.0	19.9	49.9	47.3	.240	.190	.240	1.680	1.183	1.480
31.0 - 32.0	18.9	48.9	46.3	.240	.190	.240	1.680	1.200	1.512
32.0 - 33.0	17.9	47.9	45.3	.240	.202	.240	1.680	1.252	1.534
33.0 - 34.0	16.9	46.9	44.3	.240	.220	.240	1.680	1.320	1.560
34.0 - 35.0	15.9	45.9	43.3	.240	.227	.240	1.680	1.386	1.593
35.0 - 36.0	14.9	44.9	42.3	.240	.240	.240	1.680	1.414	1.610
36.0 - 37.0	13.9	43.9	41.3	.240	.240	.240	1.680	1.458	1.614
37.0 - 38.0	12.9	42.9	40.3	.240	.240	.240	1.680	1.535	1.624
38.0 - 39.0	11.9	41.9	39.3	.240	.240	.240	1.680	1.585	1.638
39.0 - 40.0	10.9	40.9	38.3	.240	.240	.240	1.680	1.615	1.666
40.0 - 41.0	9.9	39.9	37.3	.240	.240	.240	1.680	1.646	1.680
41.0 - 42.0	8.9	38.9	36.3	.240	.240	.240	1.680	1.675	1.680
42.0 - 43.0	7.9	37.9	35.3	.240	.240	.240	1.680	1.680	1.680
43.0 - 44.0	6.9	36.9	34.3	.240	.240	.240	1.680	1.680	1.680

Exhibit A-6

MARCA NEBRASKA PUBLIC POWER DISTRICT

YEAR: 1985
WEEKLY LOAD FACTOR: OFF-SEASON 38.4
SUMMER 60.9
WINTER 62.7

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	49.9	79.9	77.3	.085	.037	.034	.085	.062	.034
1.0 - 2.0	48.9	78.9	76.3	.137	.050	.040	.137	.140	.040
2.0 - 3.0	47.9	77.9	75.3	.143	.062	.044	.168	.152	.065
3.0 - 4.0	46.9	76.9	74.3	.150	.074	.064	.251	.174	.161
4.0 - 5.0	45.9	75.9	73.3	.150	.087	.096	.282	.197	.242
5.0 - 6.0	44.9	74.9	72.3	.155	.090	.117	.305	.210	.305
6.0 - 7.0	43.9	73.9	71.3	.160	.096	.138	.310	.250	.395
7.0 - 8.0	42.9	72.9	70.3	.160	.110	.144	.365	.287	.462
8.0 - 9.0	41.9	71.9	69.3	.160	.115	.150	.483	.322	.587
9.0 - 10.0	40.9	70.9	68.3	.160	.129	.150	.598	.391	.654
10.0 - 11.0	39.9	69.9	67.3	.160	.130	.150	.757	.411	.674
11.0 - 12.0	38.9	68.9	66.3	.169	.130	.155	.798	.443	.723
12.0 - 13.0	37.9	67.9	65.3	.170	.132	.160	.807	.472	.770
13.0 - 14.0	36.9	66.9	64.3	.170	.140	.169	.862	.568	.882
14.0 - 15.0	35.9	65.9	63.3	.174	.140	.170	1.085	.609	.905
15.0 - 16.0	34.9	64.9	62.3	.180	.140	.170	1.185	.710	.931
16.0 - 17.0	33.9	63.9	61.3	.180	.140	.170	1.235	.726	.944
17.0 - 18.0	32.9	62.9	60.3	.194	.140	.170	1.264	.777	.977
18.0 - 19.0	31.9	61.9	59.3	.220	.140	.170	1.318	.822	1.036
19.0 - 20.0	30.9	60.9	58.3	.240	.149	.170	1.384	.967	1.073
20.0 - 21.0	29.9	59.9	57.3	.240	.150	.173	1.414	.992	1.106
21.0 - 22.0	28.9	58.9	56.3	.240	.150	.180	1.457	1.007	1.137
22.0 - 23.0	27.9	57.9	55.3	.240	.160	.180	1.529	1.031	1.165
23.0 - 24.0	26.9	56.9	54.3	.240	.160	.180	1.560	1.066	1.226
24.0 - 25.0	25.9	55.9	53.3	.240	.160	.180	1.560	1.089	1.300
25.0 - 26.0	24.9	54.9	52.3	.240	.160	.180	1.563	1.125	1.369
26.0 - 27.0	23.9	53.9	51.3	.240	.169	.180	1.609	1.139	1.413
27.0 - 28.0	22.9	52.9	50.3	.240	.170	.194	1.630	1.140	1.458
28.0 - 29.0	21.9	51.9	49.3	.240	.172	.201	1.666	1.149	1.479
29.0 - 30.0	20.9	50.9	48.3	.240	.190	.228	1.680	1.185	1.518
30.0 - 31.0	19.9	49.9	47.3	.240	.190	.240	1.680	1.203	1.530
31.0 - 32.0	18.9	48.9	46.3	.240	.190	.240	1.680	1.220	1.538
32.0 - 33.0	17.9	47.9	45.3	.240	.202	.240	1.680	1.260	1.550
33.0 - 34.0	16.9	46.9	44.3	.240	.220	.240	1.680	1.330	1.564
34.0 - 35.0	15.9	45.9	43.3	.240	.227	.240	1.680	1.397	1.593
35.0 - 36.0	14.9	44.9	42.3	.240	.240	.240	1.680	1.434	1.610
36.0 - 37.0	13.9	43.9	41.3	.240	.240	.240	1.680	1.473	1.614
37.0 - 38.0	12.9	42.9	40.3	.240	.240	.240	1.680	1.535	1.624
38.0 - 39.0	11.9	41.9	39.3	.240	.240	.240	1.680	1.585	1.638
39.0 - 40.0	10.9	40.9	38.3	.240	.240	.240	1.680	1.615	1.666
40.0 - 41.0	9.9	39.9	37.3	.240	.240	.240	1.680	1.646	1.680
41.0 - 42.0	8.9	38.9	36.3	.240	.240	.240	1.680	1.675	1.680
42.0 - 43.0	7.9	37.9	35.3	.240	.240	.240	1.680	1.680	1.680
43.0 - 44.0	6.9	36.9	34.3	.240	.240	.240	1.680	1.680	1.680

Exhibit A-7

YEAR: 1985
WEEKLY LOAD FACTOR: OFF-SEASON 35.4
SUMMER 57.9
WINTER 59.7

HYDROELECTRIC PLANT
WITH GENERATING CAPABILITY 1.0 PERCENT OF ANNUAL PEAK LOAD
SUMMARY OF ENERGY REQUIREMENTS
FOR OPERATION IN DIFFERENT SEASONS

PERCENT OF ANNUAL PEAK DOWN FROM SEASONAL PEAK LOAD	SEASONAL POSITION OF BASE OF HYDRO(PERCENT OF SYSTEM ANNUAL PEAK)			TYPICAL PEAK DAY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)			TYPICAL WEEKLY ENERGY REQUIRED (HOURS OF ANNUAL PEAK LOAD)		
	OFF SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER	OFF-SEASON	SUMMER	WINTER
.0 - 1.0	49.9	79.9	77.3	.010	.010	.010	.010	.015	.010
1.0 - 2.0	48.9	78.9	76.3	.010	.013	.015	.010	.023	.015
2.0 - 3.0	47.9	77.9	75.3	.016	.020	.022	.021	.041	.026
3.0 - 4.0	46.9	76.9	74.3	.045	.022	.030	.055	.068	.046
4.0 - 5.0	45.9	75.9	73.3	.055	.030	.040	.085	.080	.080
5.0 - 6.0	44.9	74.9	72.3	.078	.041	.040	.121	.100	.104
6.0 - 7.0	43.9	73.9	71.3	.103	.050	.040	.153	.135	.129
7.0 - 8.0	42.9	72.9	70.3	.137	.050	.044	.206	.150	.159
8.0 - 9.0	41.9	71.9	69.3	.143	.062	.050	.239	.172	.204
9.0 - 10.0	40.9	70.9	68.3	.155	.074	.064	.309	.212	.257
10.0 - 11.0	39.9	69.9	67.3	.160	.087	.096	.381	.259	.318
11.0 - 12.0	38.9	68.9	66.3	.160	.090	.122	.447	.293	.417
12.0 - 13.0	37.9	67.9	65.3	.168	.096	.149	.496	.309	.485
13.0 - 14.0	36.9	66.9	64.3	.170	.110	.169	.538	.347	.576
14.0 - 15.0	35.9	65.9	63.3	.174	.115	.170	.621	.379	.641
15.0 - 16.0	34.9	64.9	62.3	.180	.129	.170	.770	.443	.731
16.0 - 17.0	33.9	63.9	61.3	.180	.130	.170	.936	.489	.786
17.0 - 18.0	32.9	62.9	60.3	.194	.130	.170	1.037	.539	.865
18.0 - 19.0	31.9	61.9	59.3	.220	.132	.170	1.114	.603	.933
19.0 - 20.0	30.9	60.9	58.3	.240	.140	.170	1.261	.639	.989
20.0 - 21.0	29.9	59.9	57.3	.240	.140	.173	1.345	.714	1.026
21.0 - 22.0	28.9	58.9	56.3	.240	.140	.180	1.420	.767	1.069
22.0 - 23.0	27.9	57.9	55.3	.240	.160	.180	1.498	.807	1.111
23.0 - 24.0	26.9	56.9	54.3	.240	.160	.180	1.534	.887	1.167
24.0 - 25.0	25.9	55.9	53.3	.240	.160	.180	1.554	.933	1.247
25.0 - 26.0	24.9	54.9	52.3	.240	.160	.180	1.563	.978	1.305
26.0 - 27.0	23.9	53.9	51.3	.240	.169	.180	1.609	1.022	1.353
27.0 - 28.0	22.9	52.9	50.3	.240	.170	.194	1.630	1.063	1.377
28.0 - 29.0	21.9	51.9	49.3	.240	.172	.201	1.666	1.083	1.391
29.0 - 30.0	20.9	50.9	48.3	.240	.190	.228	1.680	1.150	1.420
30.0 - 31.0	19.9	49.9	47.3	.240	.190	.240	1.680	1.180	1.440
31.0 - 32.0	18.9	48.9	46.3	.240	.190	.240	1.680	1.200	1.478
32.0 - 33.0	17.9	47.9	45.3	.240	.202	.240	1.680	1.242	1.496
33.0 - 34.0	16.9	46.9	44.3	.240	.220	.240	1.680	1.310	1.535
34.0 - 35.0	15.9	45.9	43.3	.240	.227	.240	1.680	1.386	1.581
35.0 - 36.0	14.9	44.9	42.3	.240	.240	.240	1.680	1.414	1.610
36.0 - 37.0	13.9	43.9	41.3	.240	.240	.240	1.680	1.458	1.614
37.0 - 38.0	12.9	42.9	40.3	.240	.240	.240	1.680	1.535	1.624
38.0 - 39.0	11.9	41.9	39.3	.240	.240	.240	1.680	1.585	1.638
39.0 - 40.0	10.9	40.9	38.3	.240	.240	.240	1.680	1.615	1.666
40.0 - 41.0	9.9	39.9	37.3	.240	.240	.240	1.680	1.646	1.680
41.0 - 42.0	8.9	38.9	36.3	.240	.240	.240	1.680	1.675	1.680
42.0 - 43.0	7.9	37.9	35.3	.240	.240	.240	1.680	1.680	1.680
43.0 - 44.0	6.9	36.9	34.3	.240	.240	.240	1.680	1.680	1.680

Exhibit A-8

Designation of Electric Load Seasons by Months

Region	Winter Season Months	Summer Season Months	Off-Season Months
ECAR	November December January February	June July August September October	March April May
MAAC	November December January February	June July August September	March April May October
MAIN	November December January February	May June July August September	March April October
MARCA	December January February	June July August September	March April May October November
NPCC	November December January February	June July August September	March April May October
SERC	December January February	June July August September	March April May October November
SWPP	December January	June July August September	February March-April May October November
ERCOT	December November	May June July August September October	February March April November

Designation of Electric Load Seasons by Months

Region	Winter Season Months	Summer Season Months	Off-Season Months
WSCC	November	June	March
	December	July	April
	January	August	May
	February	September	October
ALASKA	November	May	February
	December	June	March-April
	January	July	September
		August	October
HAWAII	November	July	February
	December	August	March-April
	January	September	May
		October	June

APPENDIX B

ATTRACTIVENESS OF HYDROPOWER

The value of the renewable resource in hydropower should be emphasized. The major portion of the cost of hydropower is in repaying the initial investment. Hydropower operating and maintenance costs are comparatively minor when compared to financing costs. Financing costs remain fixed once they are contracted, which, of course, is true to all forms of power generation, but the fixed costs proportionally are larger for hydropower than for alternative forms of generation. Thus, only a small part of hydropower cost is subject to escalation, whereas for thermal plants the portion of costs subject to escalation is much higher. The relative degrees of price escalation provide a major economical attractiveness for hydropower. This appendix provides a brief hypothetical analysis to illustrate how the future attractiveness of a hydropower plant can be assessed.

Operating and maintenance costs are subject to the price changes accompanying economic conditions. For hydropower, the increase in annual operating and maintenance costs as prices increase is a comparatively small part of the total cost. For thermal-electric power, the labor and general materials component of operating and maintenance costs will increase in the same proportion as for hydropower, but the cost increase has a much more significant effect on the cost of the power and energy produced.

The relationship between financing costs and operating costs of different forms of generation are illustrated by analysis of a group of hypothetical hydropower plants and their alternatives in Tables B-1, B-2, and B-3. The effect of future price rises also is illustrated in the tables. Hydropower is compared to combustion turbine and coal-fired peaking steam alternative in Tables B-1, B-2, and B-3.

The capital costs, installed capacities, intermittent capacities, and mean annual energy production are assumed from a group of hydropower plants ranging in size from 10 MW to 100 MW. The costs per kilowatt of the hydropower plants are in a range that could have been experienced in the United States under 1979 price conditions. A large variety of costs per kilowatt are possible, some larger and some smaller than those assumed, but the numbers are illustrative of an elementary evaluation procedure. Steamplant cost is presumed as the increment to a large coal-fired unit.

The original cost of hydropower is assumed for illustration as $1,500 per kilowatt for a 50 MW plant, with higher cost per kilowatt for smaller plants and lesser cost per kilowatt for larger plants. A hydrologic environmental situation is assumed in which the hydroplant can concentrate a large part of the daily discharge into peak load hours. The hydrologic situation also is assumed to be similar for all the hydropower plants listed, so that the dependable capacities, intermittent capacities, and mean annual energy production are proportional for all of the sites. This assumption aids in illustrating the effect of size on cost.

Operating and maintenance costs for all plants are derived from FERC data. Operating and maintenance costs other than fuel are derived from annual publications by FERC which report such costs. Fuel costs are those reported monthly by FERC and are the prices prevailing generally when Appendix B was being prepared. Oil is considered in Tables B-1, B-2, and B-3 to be the fuel for combustion turbines. The use of gas, which presently costs less than oil, is not encouraged by DOE. Lately, oil prices in particular have risen considerably, and with time, prices of other fuels are expected to respond, although recent price patterns for coal and gas have been erratic. Since Tables B-1, B-2, and B-3 are purely illustrations, any fuel price applicable to any desired region or possible for the region can be inserted.

Escalation rates for fuels are merely examples shown for illustration. The general escalation rate used is 10%. The same escalation rate is used for fuels in Tables B-2. In Table B-3 the escalation rate used for coal is 12% and for oil it is 15%. None of the foregoing differentials pertain currently (the coal rate recently being at less than general escalation, while the recent escalation rate for oil has been much above the general rate), but represent a long-term judgement factor which can be changed by an analyst. The discount rate, 7 1/8%, is specified currently by the Water Resources Council.

Within the foregoing basic assumptions, Table B-1 shows that under 1979 conditions the combustion turbine alternative is the most favorable economically. Table B-2 analyzes the same three plants for 1990 conditions assuming for illustration a 10% inflation rate in general price level and fuels. For all three alternatives the financing costs in 1990 are the same as in 1979. The rise in general prices and fuel prices has changed the economic situation completely, however.

In 1990, hydropower constructed in 1979 has the lowest cost, except for the 10 MW plant when compared to coal-fired peaking steam.

The combustion turbine has become the highest cost alternative. The annual costs and benefits are discounted to 1979 at the interest rate of 7 1/8% specified by the Water Resource Council.

In Table B-3 differential inflation rates are assumed for fuels. Coal cost is assumed to escalate 2% more rapidly than other costs and oil cost is assumed to have 5% differential escalation. The results in terms of 1990 prices and discounted to 1979 show major economic advantage for hydro.

For every hydropower plant a similar analysis should be performed for the life of the plant, with losses and gains being discounted to 1979 and averaged over the plant life. Various financing and inflation rates can be used, so that the sensitivity of the valuation analysis can be assessed.

Tables B-1, B-2, and B-3 include power and energy analysis only. No account is taken of differences in reliability, which tend to increase the amount of thermal capacity required to replace a given amount of hydropower capacity. The omission of a reliability adjustment balances, or partly balances, the relative evaluations of intermittent hydropower capacity and the more firm thermal capacity. In the evaluation of the combustion turbine alternative, it could be considered that a portion of the hydroenergy replaces combustion turbine energy during on peak hours and part replaces coal-fired energy during off peak hours. A refinement such as that, depends upon the particular power system involved and is beyond the scope of this illustration. Environmental factors can be included to permit evaluation of the effects of daily discharge variation for peaking.

Tables B-1, B-2, and B-3 constitute a brief presentation. However, the following can be derived from them:

1. The construction cost of small hydropower usually is high unless there are local mitigating factors.

2. The operating cost of small hydropower unit of installation or per unit of energy production is much higher than for larger hydro.

3. Hydropower is less affected by cost escalation after plant completion than is thermal power.

4. Under normal evaluation techniques involving discounting of future benefits, it is difficult to justify small hydropower plants. Even the larger hydropower plants at less favorable sites often are difficult to justify.

5. Environmental restriction on discharge variation can handicap one of the hydropower's greatest advantages, which is rapid response to load change and ability to provide peak capacity.

6. Diversion of water from hydropower plant for other purposes reduces energy available 100% of the time and radically increases the cost of the remaining hydroenergy.

7. On an undiscounted cash flow basis, which is the way business necessarily is conducted, the attractiveness of hydropower is increased immensely.

8. Hydroenergy reduces dependence on oil imports and extends fossil-fuel reserves into the future. This one property should have a high economic value which should be credited to all hydropower installations. If hydropower received its full credits, development compatible with environment can proceed.

TABLE B-1

ILLUSTRATIVE ANALYSIS OF A TYPICAL HYDROPOWER PROJECT AT 0.35 MEAN ANNUAL LOAD FACTOR
COST SITUATION WHEN BUILT

Hydropower Plant										
Plant Data										
Installed Capacity - MW	10	20	30	40	50	60	70	80	90	100
Dependable Capacity - MW	3	6	9	12	15	18	21	24	27	30
Intermittent Capacity - MW	6	12	18	24	30	36	42	48	54	60
Mean annual energy - GWH	30.7	61.3	92.0	122.6	153.3	184.0	214.6	245.3	275.9	306.6
Cost - $ million	16.5	32	47	61.5	75	88	100	111	121.5	131
Annual Costs - 1979 Level - $ Thousands										
Capital (Assumed 15%)	$2,475	$4,800	$7,050	$9,225	$11,250	$13,200	$15,000	$16,650	$18,225	$19,650
Operation and Maintenance										
Fixed	111	165	207	244	276	305	333	360	383	407
Variable	35	54	65	76	87	96	104	113	121	128
Total	$2,621	$5,019	$7,322	$9,545	$11,613	$13,601	$15,437	$17,123	$18,729	$20,185
Annual Benefits - 1979 Level - $ Thousands										
Combustion Turbine Alternative										
Plant Data										
Installed Capacity - MW	10	20	30	40	50	60	70	80	90	100
Cost - $ million	2	4	6	8	10	12	14	16	18	20
Mean annual energy - GWH	30.7	61.3	92.0	122.6	153.3	184.0	214.6	245.3	275.9	306.6
Annual Costs - 1979 Level $ Thousands										
Capital (Assumed 17.5%)	$ 350	$ 700	$1,050	$1,400	$1,750	$ 2,100	$ 2,450	$ 2,800	$ 3,150	$ 3,500
Operation and Maintenance										
Fuel ($3.34/$10^6$ BTU, 13,500 BTU/KWH)	1,382	2,758	4,140	5,517	6,898	8,200	9,657	11,038	12,416	13,797
Other	100	200	300	400	500	600	700	800	900	1,000
Total	$1,832	$3,658	$5,490	$7,317	$9,148	$10,980	$12,807	$14,638	$16,466	$18,297
Net Benefit of Hydropower	(789)	(1,361)	(1,832)	(2,228)	(2,465)	(2,621)	(2,630)	(2,485)	(2,263)	(1,888)
Coal-fired Steam Alternative										
Plant Data										
Installed Capacity - MW	10	20	30	40	50	60	70	80	90	100
Cost $ million	7	14	21	28	35	42	49	56	63	70
Mean annual energy - GWH	30. 7	61.3	92.0	122.6	153.3	184.0	214.6	245.3	275.9	306.6
Annual Costs - 1979 Thousand	s									
$ Thousand										
Capital (Assumed 16.5%)	$1,155	$2,310	$3,465	$4,620	$5,775	$6,930	$ 8,085	$ 9,240	$10,395	$11,550
Operation and Maintenance										
Fuel ($1.20/$10^6$ BTU, 13,500 BTU/KWH)	497	993	1,490	1,986	2,484	2,980	3,476	3,974	4,470	4,967
Other	95	190	285	380	475	570	665	760	855	950
Total	$1,747	$3,493	$5,240	$6,986	$8,734	$10,480	$12,226	$13,974	$15,720	$17,467
Net Benefit of Hydropower	(874)	(1,526)	(2,082)	(2,559)	(2,879)	(3,121)	(3,211)	(3,149)	(3,009)	(2,718)

( ) Indicates negative numbers

TABLE B-2

ILLUSTRATIVE ANALYSIS OF A TYPICAL HYDROPOWER PROJECT AT 0.35 MEAN ANNUAL LOAD FACTOR
COST SITUATION IN 1990 AND DISCOUNTED TO 1979
IDENTICAL PRICE ESCALATION FOR ALL OPERATIONS AND MAINTENANCE ITEMS

Installed Capcity - Hydropower and thermal - MW	10	20	30	40	50	60	70	80	90	100
Hydropower Annual Costs - 1990 Level $ Thousand										
Capital (Based on 1979 costs)	$2,475	$4,800	$7,050	$ 9,225	$11,250	$13,200	$15,000	$16,650	$18,225	$19,650
Operation and Maintenance										
Fixed (10% annual escalation)	316	470	590	695	787	869	$ 949	$ 1,026	$ 1,091	$ 1,160
Variable (10% annual escalation)	100	154	185	217	248	274	$ 296	$ 322	$ 345	365
Total - 1990 Level	$2,891	$5,424	$7,825	$10,137	$12,285	$14,343	$16,245	$17,998	$19,661	$21,175
Annual Cost Discounted to 1979 at 7 1/8%	$1,359	$2,549	$3,678	$ 4,764	$ 5,774	$ 6,741	$ 7,635	$ 8,459	$ 9,241	$ 9,952
Annual Benefits - 1990 Level $ Thousand										
Combustion Turbine Alternative										
Annual Costs - 1990 Level $ Thousand										
Capital (Based on 1979 Costs)	$ 350	$ 700	$ 1,050	$ 1,400	$ 1,750	$2,100	$ 2,450	$ 2,800	$ 3,150	$ 3,500
Operation and Maintenance										
Fuel (10% annual escalation)	3,939	7,860	11,799	15,723	19,659	23,598	$27,522	$31,458	$35,386	$39,321
Other (10% annual escalation)	285	570	855	1,140	1,425	1,710	$ 1,995	$ 2,280	$ 2,565	$ 2,850
Total - 1990 Level	$4,574	$9,130	$13,704	$18,263	$22,834	$27,408	$31,967	$36,538	$41,101	$45,671
Total - Discounted to 1979 at 7 1/8%	$2,150	$4,291	$ 6,441	$ 8,753	$10,732	$12,882	$15,024	$17,173	$19,317	$21,465
Net Benefit of Hydropower										
1990 price level	$1,683	$3,706	$ 5,879	$ 8,126	$10,549	$13,065	$15,722	$18,540	$21,440	$24,496
1990 price level discounted to 1979	$ 791	$1,742	$ 2,763	$ 3,989	$ 4,958	$ 6,141	$ 7,389	$ 8,714	$10,076	$11,513
Coal-fired Steam Alternative										
Annual Costs - 1990 Level $ Thousand										
Capital (Based on 1979 Costs)	$1,155	$2,310	$ 3,465	$ 4,620	$ 5,775	$ 6,930	$ 8,085	$ 9,240	$10,395	$11,550
Operation and Maintenance										
Fuel (10% annual escalation)	1,416	2,830	4,246	5,660	7,079	8,493	9,907	11,326	12,740	14,156
Other (10% annual escalation)	271	542	812	1,083	1,354	1,624	1,895	2,166	2,437	2,708
Total - 1990 Level	$2,842	$5,682	$ 8,523	$11,363	$14,208	$17,047	$19,887	$22,732	$25,572	$28,414
Total - discounted to 1979 at 7 1/8%	$1,336	$2,670	$ 4,006	$ 5,341	$ 6,678	$ 8,012	$ 9,347	$10,684	$12,019	$13,355
Net Benefit of Hydropower										
1990 price level	$ (49)	$ 258	$ 698	$ 1,226	$ 1,923	$ 2,704	$ 3,642	$ 4,734	$ 5,911	$ 7,239
1990 price level discounted to 1979	$ (23)	$ 121	$ 328	$ 577	$ 904	$ 1,271	$ 1,712	$ 2,225	$ 2,778	$ 3,403

( ) Indicates negative number

TABLE B-3

ILLUSTRATIVE ANALYSIS OF A TYPICAL HYDROPOWER PROJECT AT 0.35 MEAN ANNUAL LOAD FACTOR
COST SITUATION IN 1990 AND DISCOUNTED TO 1979
FUEL PRICE ESCALATION AT HIGHER RATES THAN OTHER OPERATING MAINTENANCE ITEMS

Installed Capcity - Hydropower and thermal - MW	10	20	30	40	50	60	70	80	90	100
Hydropower Annual Costs - 1990 Level $ Thousand										
Capital (Based on 1979 costs)	$2,475	$4,800	$7,050	$ 9,225	$11,250	$13,200	$15,000	$16,650	$18,225	$19,650
Operation and Maintenance										
Fixed (10% annual escalation)	316	470	590	695	787	869	$ 949	$ 1,026	$ 1,091	$ 1,160
Variable (10% annual escalation)	100	154	185	217	248	274	$ 296	$ 322	$ 345	365
Total - 1990 Level	$2,891	$5,424	$7,825	$10,137	$12,285	$14,343	$16,245	$17,998	$19,661	$21,175
Annual Cost Discounted to 1979 at 7 1/8%	$1,359	$2,549	$3,678	$ 4,764	$ 5,774	$ 6,741	$ 7,635	$ 8,459	$ 9,241	$ 9,952
Annual Benefits - 1990 Level $ Thousand										
Combustion Turbine Alternative										
Annual Costs - 1990 Level $ Thousand										
Capital (Based on 1979 Costs)	$ 350	$ 700	$ 1,050	$ 1,400	$ 1,750	$ 2,100	$ 2,450	$ 2,800	$ 3,150	$ 3,500
Operation and Maintenance										
Fuel (15% annual escalation)	6,440	12,852	19,232	25,709	32,144	38,585	$45,002	$51,437	$57,859	$64,294
Other (10% annual escalation)	285	570	855	1,140	1,425	1,710	$ 1,995	$ 2,280	$ 2,565	$ 2,850
Total - 1990 Level	$7,075	14,122	$21,197	$28,249	$35,319	$42,395	$49,447	$56,517	$63,574	$70,644
Total - Discounted to 1979 at 7 1/8%	$3,325	$6,637	$ 9,962	$13,277	$16,600	$19,926	$23,240	$26,563	$29,880	$33,203
Net Benefit of Hydropower										
1990 price level	$4,184	$8,698	$13,372	$18,112	$23,034	$28,052	$33,202	$38,519	$43,913	$49,469
1990 price level discounted to 1979	$1,966	$4,088	$ 6,284	$ 8,513	$10,826	$13,185	$15,605	$18,104	$20,639	$23,251
Coal-fired Steam Alternative										
Annual Costs - 1990 Level $ Thousand										
Capital (Based on 1979 Costs)	$1,155	$2,310	$ 3,465	$ 4,620	$ 5,775	$ 6,930	$ 8,085	$ 9,240	$10,395	$11,550
Operation and Maintenance										
Fuel (12% annual escalation)	1,908	3,813	5,722	7,626	9,539	11,443	13,348	15,260	17,165	19,073
Other (10% annual escalation)	271	542	812	1,083	1,354	1,624	1,895	2,166	2,437	2,708
Total - 1990 Level	$3,334	$6,665	$ 9,999	$13,329	$16,668	$19,997	$23,328	$26,666	$29,997	$33,331
Total - discounted to 1979 at 7 1/8%	$1,567	$3,133	$ 4,700	$ 6,265	$ 7,834	$ 9,399	$10,964	$12,533	$14,099	$15,666
Net Benefit of Hydropower										
1990 price level	$ 443	$1,241	$ 2,174	$ 3,192	$ 4,383	$ 5,654	$ 7,083	$ 8,668	$10,336	$12,156
1990 price level discounted to 1979	$ 208	$ 584	$ 1,022	$1,501	$ 2,060	$ 2,658	$ 3,329	$ 4,074	$ 4,858	$ 5,714

APPENDIX C

SENSITIVITY ANALYSIS

APPENDIX C

SENSITIVITY ANALYSIS

General

Chapter One, "Methodology", presents high, low, and median electrical-energy forecasts for each reliability councils region and subregion within the reliability councils. The forecasts are intended to be part of an analysis of the future need for new hydropower installations. The data underlying the forecasts contained in this volume includes information on population projections, forecasts of economic activity, and energy conservation.

This appendix analyzes briefly the sensitivity of the forecasts to changes in particular factors. At present, energy conservation is one of the predominant factors affecting future electricity demand. For the most part, the conservation measures being based on the application of existing technology and practices. However, the continued increase in energy prices will most likely accelerate new technologies and new systems using less energy than existing systems. Also, the energy may be in different forms.

Data in this appendix illustrates that, assuming realistic implementation or market penetration rates, conservation might reduce electric-energy use per capita in the year 2000 by an overall average of 20 percent from a base "no conservation" case level. The increase in electric-energy demand due to changes in generation processes is more difficult to analyze, but probably is of the same order of magnitude. Thus, when the median forecasts of Chapter I are used as a base, the corresponding high and low forecasts appear to establish reasonable limits within which new hydropower capacity and energy can be analyzed.

This appendix presents the following:

1) Selected regional electrical-energy use characteristics in the residential, commercial, and industrial consumer categories.

2) Estimates of the potential impact that conservation measures may have on electrical-energy use.

3) A discussion of the population forecasts and the impact of alternative birth rate projections on population forecasts.

4) Discussion of the important considerations in peak load management and its potential influence on future regional electrical-energy use.

5) The regional impact of major technological advances such as a partial shift of private automobile from gasoline to battery powered.

Energy Use Characteristics and Potential Conservation Impacts

Electrical-energy use characteristics are identified for the following consumer categories and are described in the following sections.

Residential Energy Usage

Estimates of the potential residential energy savings from implementing various conservation measures are available from various research efforts. In this section the results of a Rand Corporation study are summarized. The study considered regional patterns of energy use, and the principal fuel sources. The continental United States was divided geographically based on the nine Census divisions and regional variations in energy use. On that basis, potential savings from both voluntary and mandated conservation measures are estimated.

In the Rand study, estimates of potential residential electrical energy savings from conservation serve as a starting figure which is combined with estimates of the potential savings in other consumer categories (i.e. commercial and industrial). The estimate of the total impact of conservation measures in all consumer categories may be used, in part, to assess the reasonableness of utility-based forecasts and to indicate the extent to which the latest utilityforecast appear to incorporate the effects of conservation measure of the types identified herein.

The impacts of different conservation measures depend on the mix of energy uses and fuels used for generation in a given region. Estimates of the regional differences in sources of fuel and in end uses are made for 1970, which is taken as the base year, and for projections to 1980, 1990, and 2000. The projection methodology recognizes the impact of fuel prices and the expected saturation of four major appliances - space heating, water heating, cooking and clothes drying and of two electric appliances - air-conditioning and home freezers.

A summary of the base year (1970) distribution of total primary energy and electrical energy by end use category is shown in Table C-1. Energy sources include (1) utility gas (2) electricity, (3) fuel oil, (4) bottled gas, and (5) coal and other.

Electricity as a percent of total residential energy use ranges from a high of 28 percent in the TVA and Southern subregions of SERC to a low of 10 to 11 percent in the NPCC, MAAC and part of the ECAR-MAIN regions. Electricity is also relatively important in the Florida and VACAR subregions of SERC (23.7 percent), in ERCOT and SWPP regions (21.9 percent) and in the NWPP and California Nevada subregions of WSCC (21.3 percent). Total energy and electrical energy by end use is measured at the point of use and does not include estimates of total primary energy required for the generation, transmission, and distribution of electrical energy or other energy.

Table C-2 summarizes residential energy use data from Table C-1 in terms of use of their electric energy component only.

The regional differences in potential electrical-energy savings due to residential conservation reflect regional differences and the importance of electricity in each end use.

The largest residential uses of electric energy vary between different regions of the country. In general, the largest end uses are as listed below:

Refrigeration
Lighting
Water heating
Space heating
Air-conditioning

The above five uses may not be listed in order of magnitude, although refrigeration is the largest single use by a large margin. The middle three uses appear to be reasonably close in amount. Air-conditioning is the largest single residential electric load in warmer regions of the country, but its use drops considerably in cooler regions. Air-conditioning consumes approximately 8 percent of total residential energy and 36 percent of the electric energy used residentially in ERCOT-SWPP. In all other regions air-conditioning varies from a low of 3 percent in NPCC to 16 percent in Florida and VACAR subregions of SERC. Electricity is the sole energy use for refrigeration, home food freezing, lighting and air-conditioning. Cooking and clothes

Table C-1
REGIONAL RESIDENTIAL CONSUMPTION OF ENERGY
PERCENTAGES DISTRIBUTION OF TOTAL PRIMARY ENERGY AND ELECTRICAL ENERGY BY END USE 1970[a/]

Census Region b/	New England	Middle Atlantic	South Atlantic	East South Central	East North Central	West North Central	West South Central	Mountain	Pacific
NERC Region(s) b/	NPCC	NPCC-MAAC	SERC	ECAR-MAIN	ECAR-MAIN	MARCA	ERCOT-SWPP	WSCC	WSCC
NERC Sub-region(s)	NEPOOL	NYPP	FLORIDA VACAR	SOUTHERN TVA				RMPA ARZ.-NM	No. CAL.-NEV. So. CAL.-NEV. NWPP

End Use	New England Total Energy (%)	New England Electric % Total	Middle Atlantic Total Energy (%)	Middle Atlantic Electric % Total	South Atlantic Total Energy (%)	South Atlantic Electric % Total	East South Central Total Energy (%)	East South Central Electric % Total	East North Central Total Energy (%)	East North Central Electric % Total	West North Central Total Energy (%)	West North Central Electric % Total	West South Central Total Energy (%)	West South Central Electric % Total	Mountain Total Energy (%)	Mountain Electric % Total	Pacific Total Energy (%)	Pacific Electric % Total
Space Heating	75.6	2.0	71.1	1.3	67.4	7.4	63.6	11.3	73.1	1.7	70.7	1.4	51.1	3.8	68.0	4.1	51.5	7.2
Water Heating	14.2	13.5	15.3	7.9	14.3	40.6	11.6	36.9	11.9	14.9	12.2	15.6	16.4	5.5	17.0	14.1	18.6	17.0
Cooking	3.8	28.7	4.8	13.6	5.2	35.6	4.7	36.1	3.5	20.8	3.8	23.7	6.5	12.1	4.3	33.0	6.2	25.4
Clothes Drying	0.8	77.8	0.8	59.0	0.9	84.3	0.8	88.4	1.0	54.1	1.0	61.0	1.1	63.0	1.0	80.4	1.5	67.0
Refrigeration Home Food Freezing	2.6	100.0	2.8	100.0	4.2	100.0	4.2	100.0	2.6	100.0	3.0	100.0	4.4	100.0	3.6	100.0	4.5	100.0
Lighting	2.1	100.0	2.3	100.0	3.1	100.0	2.8	100.0	1.9	100.0	2.0	100.0	3.1	100.0	2.5	100.0	3.4	100.0
Air Conditioning	0.3	100.0	1.0	100.0	3.9	100.0	3.6	100.0	0.8	100.0	1.5	100.0	7.8	100.0	0.5	100.0	0.8	100.0
Other	0.6	87.1	1.9	45.5	1.0	?	8.7	42.4	5.2	22.5	5.8	24.2	9.6	23.8	3.4	20.4	13.5	23.9
Total	100.0	10.8	100.0	10.2	100.0	23.7	100.0	28.1	100.0	10.7	100.0	12.3	100.0	21.9	100.0	15.0	100.0	21.3

a/ Total Primary and Electrical Energy measured at point of use basis in each Census Division.

b/ The data in this table is obtained from the Rand report where it is presented by Census Region. In this table, an attempt has been made to corrolate the NERC regions and/or sub-regions most closely associated with the Census region.

Source: Census Region Energy Data from the Rand Report "Energy Use and Conservation in the Residential Sector: A Regional Analysis," Tables 26 to 34 pages 67-75.

TABLE C-2

REGIONAL RESIDENTIAL CONSUMPTION OF ELECTRIC ENERGY BY END USE
Derived from Table C-1

Census Region	New England		Middle Atlantic		South Atlantic		East South Central		East North Central		West North Central		West South Central		Mountain		Pacific	
NERC Region(s)	NPCC		NPCC-MAAC		SERC		ECAR-MAIN		ECAR-MAIN		MARCA		ERCOT-SWPP		WSCC		WSCC	
NERC Sub-region(s)	NEPOOL		NYPP		FLORIDA VACAR		SOUTHERN TVA								RMPA ARZ.-NM		No. CAL.-NEV. So. CAL.-NEV. NWPP	
End Use	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B
Spacing heating	1.5	14	0.9	9	5.0	20	7.2	26	1.2	11	1.0	8	1.9	9	2.8	19	3.8	17
Water heating	1.9	18	1.2	12	5.8	24	4.3	15	1.8	17	1.9	16	0.9	4	2.4	16	3.2	15
Cooking	1.1	10	0.7	7	1.8	7	1.7	6	0.7	6	0.9	7	0.5	2	1.4	10	1.6	7
Clothes drying	0.6	6	0.5	5	0.8	3	0.7	2	0.5	5	0.6	5	0.7	3	0.8	5	1.0	5
Refriger-ation	2.6	25	2.8	27	4.2	17	4.2	15	2.6	24	3.0	25	4.4	21	3.6	25	4.5	21
Ligthing	2.1	20	2.3	22	3.1	13	2.8	10	1.9	18	2.0	16	3.1	14	2.5	17	3.4	16
Air Conditioning	0.3	3	1.0	10	3.9	16	3.6	13	0.8	8	1.5	12	7.8	36	0.5	3	0.8	4
Others	0.5	4	0.8	8	-	-	3.7	13	1.2	11	1.4	11	2.3	11	0.7	5	3.2	15
Total	10.6	100	10.2	100	24.6	100	28.2	100	10.7	100	12.3	100	21.6	100	14.7	100	21.5	100

A - Percent of total energy used for residential purposes in the Census region.
B - Percent of electrical energy used for residential purposes in the Census region.

drying, while using significant amounts, of energy in all regions, are smaller in magnitude overall than the five major residential uses.

Residential Conservation Measures

The conservation measures are identified and classified as follows:[a/]

"Group I: Measures that (a) would have to be undertaken voluntarily by the households, (b) are not directly controllable by law, and (c) are primarily operational. In this group are measures the households would be most likely to implement in response to rising energy prices or energy rationing". Included in this group are measures number 1, 2, 8, 11, and 12 of Table C-3.

"Group II: Measures related to the energy efficiency of major appliances that would be most likely to be covered by appliance labeling laws or minimum appliance efficiency standards". Included in this group are measures number 5, 6, 10, 13 and 14 of Table C-3.

"Group III: Measures to improve the thermal integrity of existing houses such as installing ceiling insulation in attic crawl spaces". This includes measure number 4 in Table C-3.

"Group IV: Measures to improve the thermal integrity of new residential structures, such as by including minimum insulation requirements in building codes". Included in this group is measure number 7, Table C-3.

"Group V: Consists of (1) measures that would have to be undertaken voluntarily but, are not considered to be cost effective, and (2) measures that could be mandated but where primary energy savings are projected at less than 0.2 percent of base case primary energy consumption in most cases." These measures, numbers 3 and 9, are not considered further.

The Rand study points out that other conservation measures can produce additional energy savings, but have not been quantified and included in the above figures.[b/] These measures, which as related to replacing electric resistance heating by other forms of heating, are

a/ Rand Report: Energy Use and Conservation, page 115.

b/ Rand Report, page 88.

Table C-3

POTENTIAL ENERGY CONSERVATION MEASURES

Measure	Conservation Measure Group	Method to Obtain	Form of Energy Saved: Oil	Gas	Elect.	Type of House or Appliance: Old	New
Related to Heating							
1-Furnace thermostat set back	I	V	x	x	x	x	x
2-Furnace tune-up	I	V	x	x		x	x
3-Gas furnace electric ignition, retrofit	V	V		x		x	
4-Improve thermal integrity of existing structure[a]	III	V	x	x		x	
5-New gas furnace electric ignition	II	M		x			x
6-Improve new furnace	II	M	x	x			x
7-Improve new structures[a]	IV	M	x	x			x
Related to Cooling							
8-Central A/C thermostat set up	I	V			x	x	x
9-Central A/C tune-up	V	V			x	x	x
10-Improve A/C efficiency, room and central	II	M			x		x
Related to Water Heating							
11-Water heater thermostat set back	I	V	x	x	x	x	x
12-Reduce hot water use	I	V	x	x	x	x	x
13-Improve water heater insulation	II	M	x	x	x		x
Other Functions							
14-Improve refrigerator-freezer efficiency	II	M			x		x
15-Gas range electric ignition		M		x			x
16-Gas dryers electric ignition		M		x			x

a/ These measures would also save electricity in air-conditioned structures that are heated with gas or oil. These savings are not estimated, however, because of lack of information on the saturation of air-conditioning according to type of heating plant.

Note: V = voluntary; M = could be mandated; x = Applicable to form of energy shown.

Source: Rand Report, Table 39, page 89

1) Solar energy for water and space heating
2) Heat Pumps to replace electric resistance heating
3) Substitution of gas for electric appliances.

Measure number 3 is of doubtful long term efficiency. At present and in the near future, gas supplies appear ample for residential needs although a few years ago there were restrictions on supplying gas to new residences because of projected shortages. It is not possible to guarantee that there will not be a future shortage of gas. The overall efficiency of measure 1 remains to be proven, particularly when the original manufacture, installation, operating and maintenance requirements are considered. Measure 2 contains significant promise.

The three measures were not analyzed in the Rand study because of difficulty in obtaining precise data relative to "industries for manufacturing and installing (solar),.... regional difference in utility [effect which] would have been too difficult to assess within the scope of the study,....wide divergence of published opinion on the future potential of heat pumps and lack of reliable information on the effects of climatic variations on future heat pump efficiencies....The technological capability does not yet exist to select suitable equipment sizes and to install the equipment in such a way as to achieve currently attainable efficiencies".

Also not included as noted in a footnote, Table C-3, are the effects of measures number 4 and 7 - improving thermal integrity of existing and new structures in saving electricity in air-conditioned structures that are heated with gas and oil.

Using results of the Rand study estimates are made of the range in potential residential electrical savings expressed as a percent of a base case level of consumption for the year 2000, for each NERC region.

Conservation Group

NERC Region	I	II	III	IV	V	Total
	(Percent of Base Case Consumption level)					
WSCC	12-19	11-17	-	-	-	23-30
MARCA	12	15	-	-	-	27
SWPP	13	17	-	-	-	30
ERCOT	13	17	-	-	-	30
SERC	19	12-13	-	-	-	31-32
MAAC	12	15	-	-	-	27
NPCC	10-15	12-16	-	-	-	22-27
MAIN	10	13	-	-	-	23
ECAR	10	13	-	-	-	23

The potential savings in electrical-energy consumption with the conservation measures described above range from 23 to 32 percent of the base case consumption level for the year 2000. Implementation of additional measures not quantified would result in savings the magnitude of which may vary by region.

Commercial Energy Usage

The commercial consumer category includes the demands of widely differing types of users including wholesale and retail trade, communication, utilities, except electric, finance, real estate, insurance, services, and construction. The types of buildings include stores. The relative importance of the commercial category in a region's total consumption of electricity varies greatly. Based on 1978 data, commercial consumption contributed approximately 6 percent to the total annual electrical consumption in the SERC-TVA subregion compared to a high of 38 percent in the WSCC-RMPA subregion. The U.S. average was approximated as 24 percent for the same year.

The principal sources of demand for electricity of commercial consumers are concentrated in the following: lighting, space heating and cooling, ventilation, and water heating. Several studies[a/] prepared by the Rand Corporation analyze electrical consumption of

a/ 1) Energy Alternatives for California: Paths to the Future, December, 1975.
2) California's Electricity Quandary: III Slowing the Growth Rate, September, 1972.

commercial users and provide estimates of the potential impact of various conservation measures on consumption. Results of the findings are discussed in the following section.

Commercial Conservation Measures

Measures to reduce commercial electricity usage tend to fall into one of three categories: (1) modifying the usage patterns of existing electrical systems, (2) using smaller or more efficient types of systems, and (3) using systems that consume non electric energy. The regional impact of the various conservation measures is dependent on the relative importance of large consumptive uses such as electric heating and central air-conditioning. One estimate of the impact of various conservation measures may have on commercial consumption is given in the Rand Report in Table 14.4 page 199[a/] (reproduced here as Table C-4).

As indicated in Table C-4 the total potential for savings is estimated at 45 percent in electricity use compared to use with no conservation action. The Rand study points out that the fraction of the potential savings achievable will depend on the degree to which building owners and operators respond to energy price changes and the extent of government encouragement and inducement to adopt energy savings in commercial buildings. Most of the opportunities for energy savings result from changes in operational procedures (such as reduced lighting levels, changes in thermostat settings, and heating and cooling schedules).

Data on the regional differences in electrical-energy use in the commercial category are incomplete. The actual market acceptance of the various conservation measures in each region can not be estimated accurately at this time. However, there is no doubt that opportunities exist for realizing substantial savings.

Industrial Energy Usage

The use of electrical energy for industrial purposes is concentrated by geographical area and industrial sector. Approximately 72 percent of the electricity purchased by manufacturers is consumed by 7 industrial sectors located in 15 states. Approximately 85 percent of purchased electricity is consumed by 10 industrial sectors.[a/]

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a/ Energy Alternatives for California --- December, 1975.

b/ Sources: The 1976 Annual Survey of Manufacturers and to 1977 Census of Manufacturers, Department of Commerce.

Table C-4

COMMERCIAL SECTOR CONSERVATION MEASURES

Category	Conservation Measures	Example of Action [a]	Energy Savings Potential (%) [b]: New Construction, Electricity	New Construction, Fossil Fuel	Existing Building, Electricity	Existing Building, Fossil Fuel
BUILDING USE AND OPERATION	Lighting reduction	A 50% reduction in sector lighting energy from an assumed base of 10.4 kWh/ft^2 (2.7 W/ft^2 on 44% schedule to 2.0 W/ft^2 on 30% schedule	33	-19	33	-19
	Internal temperature control	A 6-deg increase in cooling thermostat setting and a 6-deg decrease in heating thermostat setting	4	32	4	32
	Equipment maintenance and feedback control	An average of the 5% to 12% savings estimated by the FPC[c]	8	8	8	8
	Operation schedule (including automated control)	A 10% reduction in use of air-conditioning and heating equipment	3	1	3	1
	Reduced ventilation (& infiltration)	A 50% reduction in both new and old building	--	8	--	8
	Reduced decorative & outdoor lighting	A 1% sector energy reduction	2	--	2	--
SYSTEMS AND EQUIPMENT	Balancing heat eliminated	A 75% reduction in use of balancing heat distribution systems	--	5	--	2
	Thermal energy conservation systems	A 50% increase in use of: (1) lighting heat isolation, (2) ventilation enthalpy exchange, (3) economizer systems in new building and a 10% retrofit	1	5	--	1
	Chiller waste heat recovered	A 33% introduction of double-bundle condensers in new construction and 10% in existing construction	--	3	--	1

Table C-4 (Continued)

Conservation Measures	Example of Action a/	Energy Savings Potential (%) b/ — New Construction: Electricity	New Construction: Fossil Fuel	Existing Building: Electricity	Existing Building: Fossil Fuel
Reduced window area	A 25% reduction of window area in new building	--	14	--	--
Use of insulating glass	A 50% introduction of insulating (double) glass in both new and existing buildings	-1	16	-1	16
Installation of external shades and filtering glass	A 25% reduction in solar flux	1	--	1	--
Increased insulation	A reduction of 0.1 in the current industry average U factor in new building walls; no retrofit	--	7	--	--
Building orientation	A change from random orientation of 50% of new structures to an optimum orientation	--	--	--	--
Aggregate of all measured[d]		45	60	44	51

NOTE: The dash (--) indicates the amount is negligible.

a/ See, for example, Salter, Petruschell, and Wolf, Energy Conservation.
b/ Relative to the high use case.
c/ Federal Power Commission, Guidelines for Energy Conservation for Immediate Implemenation, Washington, D.C., January 1974.
d/ Compensated for nonadditive effects.

Source: Rand Report, Table 14.4, Page 199 "Energy Alternatives for California" -- December, 1975.

A summary of industrial electrical-energy use for the Nation and for selected states and industrial sectors, are given in Tables C-5, C-6, & C-7.

Primary metals is the most important electrical-energy using sector with 23 percent of the U.S. total purchase of industrial electrical energy in 1977. Other important consuming sectors are chemical and allied products (22.6 percent), paper and allied products (6.4 percent) and food and kindred products (6.3 percent). These four industrial sectors accounted for 58 percent of industrial electric energy purchases in the United States in 1977.

Geographical location of important industrial users are concentrated in Ohio with 8.9 percent of the U.S. total in 1976, followed by Texas (7.8 percent), California (5.7 percent), Pennsylvania (5.5 percent), New York (5.2 percent) and Tennessee, Illinois, Kentucky and Michigan with each state accounting for between 4.5 and 4.9 percent of the U.S. total electricity consumed by industry.

Industrial Energy Conservation Potential:

Data presented below show the following potential electric-energy savings in a group of major industries. The table presents an indicated average potential savings of approximately 20 percent overall in the industrial category based on the estimated savings derived for specific industries.

SIC	Industry	Year 2000 Percent Reduction Probable in Electric Energy a/ %
28	Chemicals	25
20	Food and Kindred Products	15
32	Stone, Clay & Glass	25
29	Petroleum Refining	25
3312	Blast Furnance & Steel Mills	
	1976-1980	4
	1980-2000	24 b/
3334	Aluminum Smelting	
	1976-1980	3
	1980-2000	15

a/ From a base case "no conservation" unit usage level assumed to be that experienced during the period 1972-1976.

b/ Representative of improved efficiency, but not necessarily reflecting overall savings in electric-energy use due to the desirability of electric furnaces.

Table C-5

MAJOR USE OF ELECTRICITY BY INDUSTRY CLASSIFICATION, BY REGION

NERC REGION	SIC Group	Industry
ECAR	33	Primary Metals - Blast Furnace & Steel Mills
	28	Chemical and Allied Products: inorganic
	37	Motor Vehicle Parts & Equip
	34	Fabricated Metal Product
SERC	28	Industrial inorganic Chemicals
	33	Primary Metals, Blast Furnace
	22	Textile Mill Products
	26	Paper and Allied Products
WSCC	29	Petroleum and Coal Products: Refining
	33	Primary Metals: Primary Aluminum
	20	Food and Kindred Products
	26	Paper and Allied Products
	24	Lumber and Wood Products
	37	Transport Equipment
MAAC	33	Primary metals, Blast Furnaces, Basic Steel
	28	Industrial inorganic chemicals
	32	Stone, Glass and Clay
	26	Paper mills & Allied Products
	20	Food and Kindred Products
NPCC	33	Primary Metals, Nonferrous metals
	28	Industrial inorganic chemicals
	20	Food and Kindred Products
	26	Paper mills & Allied Products
MAIN	33	Primary metals, Blast Furnace, Basic Steel
	28	Chemicals: organic & inorganic and Plastics
	35	Machinery except Electrical
	34	Fabricated Metal Products
	29	Petroleum and Coal Products
ERCOT	28	Chemicals: organic, inorganic, Plastics
	33	Primary nonferrous metals
	29	Petroleum refining
SWPP	28	Chemicals: organic & inorganic
	29	Petroleum refining
	26	Paper mills & Allied Products
MARCA	20	Food and Kindred Products
	26	Paper and Allied Products
	28	Chemical, Allied Products
	29	Petroleum and Coal Products
ALASKA	20	Food and Kindred Products
	24	Lumber and Wood Products
HAWAII	20	Food and Kindred Products
	32	Stone, Clay, Glass Products

Table C-6

ELECTRICAL ENERGY USED BY MAJOR SIC INDUSTRIAL GROUP AND SELECTED INDUSTRIES, 1977

SIC		Industry Category	Percent of Total U.S. (1977) a/ (%)	Cumulative Total
33		Primary Metals	23.0	23.00
	3334	Primary Aluminum	(9.3)	
	3312	Blast Furnaces & Steel Mills	(6.9)	
28		Chemical and Allied Products	22.6	45.60
	2819	Inorganic Chemicals NE-C	(8.2)	
	2869	Organic Chemicals NE-C	(3.5)	
	2821	Plastics materials & Resins	(1.4)	
	2812	Alkali and Chlorine	(1.8)	
	2824	Organic Fibers, non-cellulosic	(1.1)	
	2873	Nitrogenous Fertilizer	(0.8)	
	2865	Cyclic crudes and intermediate	(0.8)	
26		Paper & Allied Products	6.4	52.00
	2621	Paper mills, excluding building paper	(3.0)	
	2631	Paper board mills	(1.6)	
20		Food & Kindred Products	6.3	58.30
32		Stone, Clay & Glass Products	4.8	63.10
	3241	Cement, hydraulic	(1.5)	
	3221	Glass containers	(0.7)	
37		Transportation Equipment	4.7	67.80
	3714	Motor Vehicle Parts & Equipment	(1.7)	
29		Petroleum & Coal Products	4.6	
	2911	Petroleum Refining	(4.2)	
35		Machinery Except Electrical	4.3	76.70
34		Fabricated Metal Products	4.2	80.90
22		Textile Mill Products	4.2	85.00

a/ In Percent of U.S. Total Industrial Electrical Energy Purchasers.

Source: 1977 Census of Manufactures Dept. of Commerce.

Table C-7

MAJOR ELECTRICAL ENERGY USE BY SELECTED STATES

New Selected States[a/]	Percent of Total U.S. Industrial Electrial Energy Consumption (1977)[b/] %	NERC Region	Major Industrial Consumers by SIC Group[c/]	Percent of State Total %
State				
Ohio	8.9	ECAR	281(30),331(19),34(6),371(5)	60
Kentucky	4.6		28(63),33(22)	85
Michigan	4.4		371(28),331-332(24),34(10),281(4)	66
Indiana	3.9		331(23),281(6),371(5),34(4),32(5)	43
	(21.8)			
Tennessee	4.9	SERC	281(48),33(20),26(5)	73
Alabama	3.5		33(41),28(19),26(11),22(10)	81
N.Carolina	3.3		22(42),28-282(14),26(5)	61
	(11.7)			
California	5.7	WSCC	291(14),20(10),37(10),28(9), 32(8),33(8), 36(8)	67
Washington	3.6		333(61),26(18),28(5)	84
	(9.3)			
Pennsylvania	5.5	MAAC	33(38),28(8),32(8),26(6),20(6), 34(5)	71
New Jersey	2.5		28(25),32(9),20(8),26(7),30(7), 33(7)	63
	(8.0)			
New York	(5.2)	NPCC	33(24),28(9),20(8),26(6),32(5), 27(5),27(5),23(5),34(5)	67
Illinois	(4.8)	MAIN	33(25),28(11),(35(10),34(8), 29(8), 36(5)	67
Texas	(7.8)	ERCOT	28(39),33(16),29(14),20(5), (35(5),32(4)	83
Louisiana	(3.4)	SWPP	28(59),29(16),26(10)	85
Minnesota	9.7	MARCA	20(18), 26(17), 35(11), 29(7)	53
Iowa	1.0		20(28), 28(15), 35(14), 33(11)	68
	(10.7)			
Alaska	(0.02)	ALASKA	20(43), 24(29)	72
Hawaii	(0.07)	HAWAII	20(43), 32(14)	57

a/ Fifteen state using approximately 72 percent of total U.S. industrial electrical energy in 1977.

b/ Electrical energy purchased, excludes self-generated which represented approximately 8.5 percent of total U.S. industrial electrical energy consumed in 1977.

c/ Figures in parenthesis are the percentage of the state's total purchased electrical energy consumed by each SIC industry group.

Source: Annual survey of manufacture 1976

Rand studies previously referred to consider the potential impact of conservation measures in selected industries. The possibilities for reducing electricity consumption are more difficult to estimate in industry than in residential and commercial classifications. The reason given is that "electricity energy use in manufacturing is dominated by the technical requirements of production, particularly those relating to mechanical functions or electrochemical reactions. The "process uses" of electricity are vital to the operation of industries, so that industrial saving of electric energy a different approach than commercial savings". a/

The Rand study of California analyzes industries in that State Many of the industries also operate in many other states, so that the Rand study results are considered representative of potential impacts nationwide.

Four of the two-digit Standard Industrial Classification (SIC) groups in manufacturing account for over 60 percent of the total use of energy in California, and provide almost all of the chemical feedstocks. These are petroleum refining (SIC 29), stone, clay, and glass (SIC 32,) food and kindred products (SIC 20), and chemical (SIC 28). These four manufacturing groups thus represent major possibilities for energy savings.

Studies of possible energy conservation measures in selected industries indicate the following potential savings may be achieved:

Petroleum Refining. b/ Energy is used in refineries in three principal ways:" (1) to raise steam, (2) as direct process heat, and (3) as electricity for pumps and motors." Pumps and motors usually are electrically driven. The conservation measures most frequently mentioned as warranting greater use in refineries are waste heat recovery devices of various kinds and for different points of application:

On site generation of electricity,
Power recovery from liquid and gas process steams,
Combined gas turbine-boiler steam turbine systems for process steam, heat, and electricity,
Improved combustion control,

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a/ Quotes from the Rand Report: California's Electricity Quandry. III Slowing the Growth Rate, page 86.

b/ Quotes from the Rand Report: Energy Alternatives for California: Paths to the Future, page 204.

Air cooling; and
Improved design of distillation units.

The application of the conservation techniques mentioned above could reduce energy use per unit of output from 18 to 25 percent below current levels by 1990. Considering co-generation it is probable that net savings can be 25 percent.

Stone, Clay, and Glass.[a/] Stone, clay and glass include the cement industry which is highly energy intensive. The consumption of energy per unit of output is, among the highest for any industry, thus making the cement industry sixth largest in total use of energy by all U.S. industry. The U.S. cement industry for many years has operated in an atmosphere of high labor costs and low fuel costs. This combination dictated the construction of simple plants with low labor costs rather than good fuel economy. Because of rising fuel costs, the policy is changing. As in the chemical process industry, U.S. cement producers are now turning to the practices of producers in Europe and Japan, where for many years the industry has had relatively high fuel costs.

Because of the nature of cement manufacture, the predominant uses of electric energy are for the mechanical operations of crushing, grinding, and blending - and for kiln heating to achieve chemical changes. Of these applications," 75 to 85 percent of the energy consumed is in direct fuel burning in the kiln." Thus, conservation possibilities in the cement industry would mostly be on kiln design and operation. Electric-energy savings in mechanical operations probably would not exceed 25% of the electric energy used, co-generation might be a possibility.

Food and Kindred Products[b/]

The food processing industry is a large user of energy. In California, for example, its consumption of energy is almost 15 percent of the total used by California's manufacturers. " The industry classification includes such diverse operations as meat packing (SIC 2011), fluid milk (SIC 2026), canned fruits and vegetables (SIC 2033), frozen

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a/ Quotes from the Rand Report: Energy Alternatives for California: Paths to the Future, page 204.

b/ Quotes from the Rand Report: Energy Alternative for California, page 205.

fruits and vegetables (SIC 2037), prepared feeds (SIC 2042), and bread cake, and related products (SIC 2051)." Electric energy is used for driving grinders, conveyors, and blowers, and for refrigeration. "More efficient energy use could reduce the energy per unit of output by about 25 percent in meat packing, 27 percent in milk processing, about 5 percent in canning and 27 percent in bread products." The average reduction in electric-energy use may be projected at approximately 15 percent.

Chemicals[a/]

The chemical industry uses large quantities of electric energy, particularly in electro-chemical processes. Electricity also is used to drive pumps, conveyors, and blowers. "Many chemical products can be made from a wide variety of raw materials and by several different processes. The combination of feedstocks and process employed is normally the one with the lowest overall costs at the time the plant is designed and constructed. As the cost for an important input factor such as energy rises significantly, total costs may sometimes be reduced if the feedstock, the process, or both, are changed. The chemical industry should benefit from European and Japanese industries by selecting process and feedstock combinations to conserve energy. These foreign manufacturers have been forced to operate for a number of years using high-cost energy. They have developed production devices and combination of feedstocks and processes that minimize costs under these circumstances.

It has been estimated that most chemical industries could reduce their use of energy per unit of output by from 10 to 50 percent over the next 10 years, with the possible exception of alkalis and chlorine, where necessary technology may not be available, and synthetic rubber, where new products are more energy intensive." An average of 25 percent appears reasonable.

Primary Metals

For the primary metals group a report prepared by the Conference Board[b/] presents data on changes in energy use per unit of output and

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a/ Quotes from the Rand Repot: Energy Alternative for California, page 206.

b/ Energy Consumption in Manufacturing. The Conference Board, 1974. pages 441 and 556.

projected changes expected between 1972 and 1980. For blast furnaces and steel mills (SIC 3312) energy saving per ton of steel are projected to average one percent annually through 1980. For aluminum smelting (SIC 3334) changes in energy use per unit of output are projected to average 0.63 percent annually for the 1971-80 period. For rough estimates of potential energy savings in the year 2000, simple linear extrapolations from a base year (say 1976) would show savings of 24 percent for blast furnaces, and steel mills (SIC 3312) and aluminum smelting (SIC 3334).

Environmental conditions are an important factor in the evaluation of electric-energy use by the steel industry. In many locations, electric furnaces are less costly and more efficient than alternative production methods because the cost of controlling pollution is reduced. Thus, even though electric energy will be used more efficiently, there is the possiblity of an increase in electric-energy use per ton of steel produced.

General

Studies of industrial energy consumption point out that savings from housekeeping improvements may be expected fairly quickly compared to savings from improved technology requiring substantial investment in new machinery.

The major industrial users of electrical energy are concentrated in the ECAR, SERC, NWPP, MAAC regions, with a combined total of 68 percent of the U.S. total consumption in 1977. Chemicals (SIC 28) and primary metals (SIC 33) are the dominant industries in these regions. For the industrial category, generally, energy conservation impacts may be expected, on the average, to result in a reduction from the base case "no conservation" level, of approximately 20 percent.

Population Forecasts

Population forecasts, one of the major inputs used in electricity projections, are sensitive to assumptions concerning the following factors:

1) The amount of net immigration, and its age, race, and sex,

2) The age-specific mortality rates, and

3) The age-specific birth rates.

The first two factors are relatively easy to quantify. However, there is considerable variation in estimation of future birth rates.

The basic population projections assumes an ultimate level of completed cohort fertility (average births per woman) of 2.1 in the year 2005. Alternative projections of fertility rates may reach ultimate levels of 1.7 and 2.8 births per woman. The national population in the year 2000 is about 10 percent higher when a fertility rate of 2.8 is used rather than 2.1. This same result can be obtained by a 50% increase in the population growth rates that are reflected in the basic projections. Table C-8 gives the percentage increases in the 1985 and 2000 energy demands of Projections II and III due to a 15% and 50% increase in population growth rates. When an ultimate fertility rate of 1.7 births per woman is used, the resulting population is 7 percent lower than the population resulting from a fertility rate of 2.1 births per woman. With a rate of 1.7 births per woman, the national overall growth rate would decrease from 0.8% to 0.5% for the study period 1978-2000, representing a 40% decrease in the national population growth rate.

Regional Load Growth Pattern

Two tables present data illustrating the difficulties in projecting regional electric load growth while showing the basis for assuming uniform per capita growth rate throughout the country. Table C-9 shows regional and national electric-energy usage for the twelve months of 1978. Table C-10 shows monthly regional and national load factors for the same period. Energy use in all parts of the country except Hawaii shows the same general pattern. Hawaii represents only 3% of national electrical-energy use and, therefore, has a minor influence on the national pattern.

The regions shown vary in major degrees in climate, industrial activity, population density, and agricultural production, yet the same major pattern of electric energy use applies throughout. This major pattern illustrates energy use for heating and cooling super-imposed on the basic economic activities and provides the basis for assuming constant rate of load growth throughout the country.

The difficulties of projecting growth rate by regions are shown by variations between regions in the monthly patterns of electric energy use and load factor. From one month to another energy use changes by a different percentage in one region than in another. Monthly load factors rise and fall erratically within regions. The variations are attributed to various causes that cannot be clearly identified.

Table C-8

REGIONAL AND subregional PERCENT OF ELECTRICAL ENERGY INCREASE DUE TO A 15% AND A 50% INCREASE IN THE PROJECTED POPULATION GROWTH RATES FOR PROJECTIONS II AND III

	1985		2000	
	15%	50%	15%	50%
ECAR	0.6	2.1	2.1	7.1
Allegheny Power System	0.5	1.8	0.9	2.8
American Electric Power	0.5	1.7	1.9	6.4
Central Area Power Coordination Group	0.4	1.4	1.6	5.5
Cincinnati Columbus Dayton Group	0.5	1.9	2.1	7.1
Michigan Electric Coordinated System	0.7	2.5	2.4	8.5
Kentucky Indiana	1.0	3.1	3.0	10.3
MAIN	0.5	1.8	1.9	6.4
Commonwealth Edison Subregion	0.6	1.8	2.2	7.5
Wisconsin Upper-Michigan Subregion	0.9	2.6	2.0	6.6
Illinois Missouri Subregion	0.4	1.4	1.5	5.0
MAAC	0.4	1.4	2.1	7.1
MARCA	0.5	1.7	1.5	5.1
NPCC	0.4	1.4	2.1	7.2
New England Subregion	0.7	2.4	2.4	8.5
New York Subregion	0.2	0.7	1.9	6.3
SERC	1.6	5.5	4.2	14.9
Virginia Carolinas Subregion	1.4	5.0	4.1	14.4
Tennessee Valley Authority	1.3	4.5	3.3	11.5
Southern Companies Subregion	1.2	4.2	3.0	10.3
Florida Subregion	2.7	9.2	6.6	23.7
SWPP	0.9	3.2	2.0	6.8
ERCOT	1.6	5.3	3.7	12.8
WSCC	1.5	5.0	3.3	11.5
Northwest Power Pool Area	1.2	4.2	2.6	8.7
Rocky Mountain Power Area	1.7	6.0	3.6	12.5
Arizona New Mexico Power Area	2.3	8.0	5.0	17.9
S. California Nevada Power Area	1.3	4.2	3.3	11.4
N. California Nevada Power Area	1.7	5.7	3.9	13.5
ALASKA	3.1	9.3	5.2	19.0
HAWAII	1.1	5.5	4.4	15.2
NATIONAL	1.1	3.6	2.9	10.0

Table C-9

MONTHLY ENERGY CONSUMPTION (GWh)

1978	ECAR	MAAC	MAIN	MARCA	NPCC	SERC	SWPP	ERCOT	WSCC	ALASKA	HAWAII	NATIONAL
January	34,807	15,540	15,154	8,744	18,284	43,208	15,609	11,540	34,423	275	521	198,105
February	29,459	13,989	13,502	7,857	16,388	37,880	14,113	10,253	30,699	234	478	174,852
March	28,890	14,305	13,629	7,578	17,263	35,283	13,975	10,241	32,469	241	527	174,401
April	26,975	12,534	12,129	6,681	15,297	31,161	13,322	10,114	31,287	197	510	160,207
May	29,184	13,032	13,203	6,718	15,517	35,454	15,278	12,618	32,851	184	536	174,575
June	30,219	14,029	14,119	7,272	15,949	39,411	17,582	14,189	34,381	171	526	187,848
July	31,311	14,737	15,329	8,142	16,591	41,631	20,826	16,189	36,431	173	550	201,910
August	32,763	16,405	15,678	8,389	17,822	43,059	19,711	15,522	36,531	184	567	206,631
September	30,770	13,515	14,468	7,626	15,438	39,049	17,627	13,511	33,090	192	544	185,830
October	30,597	13,238	13,216	7,241	16,046	34,803	14,297	11,372	34,287	233	561	175,891
November	30,706	13,491	13,413	7,629	16,307	34,143	13,878	10,501	35,523	260	528	176,379
December	33,427	14,951	14,972	8,600	17,964	37,668	15,332	11,329	38,163	282	520	193,208

Source: Regional Electric Reliability Councils Reports, April 1, 1979.
Monthly Energy Data Reports - Electric Power Statistics - DOE/IEA-0034.

Table C-10

MONTHLY LOAD FACTORS

1978	ECAR	MAAC	MAIN	MARCA	NPCC	SERC	SWPP	ERCOT	WSCC	ALASKA	HAWAII	NATIONAL
January	0.764	0.743	0.748	0.760	0.733	0.722	0.779	0.771	0.750	0.679	0.663	0.746
February	0.751	0.802	0.786	0.791	0.766	0.704	0.806	0.773	0.750	0.675	0.681	0.751
March	0.774	0.750	0.764	0.726	0.763	0.703	0.760	0.727	0.727	0.692	0.675	0.738
April	0.753	0.737	0.752	0.743	0.752	0.738	0.775	0.727	0.768	0.667	0.687	0.745
May	0.720	0.692	0.656	0.643	0.695	0.690	0.670	0.704	0.702	0.678	0.712	0.692
June	0.696	0.660	0.617	0.626	0.690	0.680	0.668	0.722	0.715	0.645	0.731	0.683
July	0.683	0.651	0.635	0.644	0.658	0.710	0.730	0.759	0.713	0.657	0.718	0.691
August	0.729	0.693	0.639	0.641	0.687	0.724	0.690	0.741	0.718	0.642	0.728	0.703
September	0.690	0.636	0.616	0.602	0.692	0.687	0.675	0.701	0.680	0.664	0.708	0.674
October	0.772	0.777	0.775	0.746	0.749	0.733	0.699	0.655	0.716	0.680	0.695	0.731
November	0.765	0.726	0.728	0.713	0.685	0.736	0.760	0.735	0.750	0.676	0.670	0.733
December	0.770	0.750	0.751	0.740	0.717	0.705	0.769	0.731	0.748	0.671	0.664	0.735

Source: Computed from Peak and Energy presented in the two following reports:
a: Regional Electric Reliability Councils Reports April 1, 1980.
b: Monthly Energy Data Reports - Electric Power Statistics - DOE/IEA-0034

Variations of temperature and rainfall from normal, increases or decreases in industrial activity, and regional variations in population movement all affect electric-energy use and load factor.

Future changes in the price and availability of fuels also will affect regional electric-energy use. For example, if oil and gasoline for transportation use become in short supply, there will be an impetus to develop and use battery-powered vehicles. Radical energy supply and price changes may also lead to shift in manufacturing locations. Such shift, however, will be based secondarily on energy supply aspects and will result, primarily from changes occurring in regional labor, economic, and political conditions. Developments of this nature are, at present, as unpredictable in detail as the impact of the automobile and airplane were one hundred years ago, although, even then, far sighted individuals could visualize them. The adjusted OBERS projections contain a reasonable basis for establishing regional population trends and when combined with the alternative projections of per capita growth in energy usage, provides a realistic framework for estimating future trends in electric-energy use.

Load Management

Virtually every projection of electric utility load assumes a relatively stable annual load factor. Growth in total energy consumption and peak demand are assumed to be at essentially equal rates, resulting in an ever-increasing disparity between base and peak loads. Through load management techniques, energy-consuming activities during peak load hours may be shifted to hours during which electrical demand is not so great. The result is a larger load factor and a greater productivity of the electric utility system.

The primary load management techniques which have the effect of modifying the load pattern are:

1) Voluntary or mandatory control of peak load,
2) Time dependent, cost-based electrical rates,
3) Use of thermal-energy storage systems, and
4) Electric highway vehicles.

Certain consumer loads can be controlled to a degree with no particular inconvenience to the consumer. At present, water and space heating are deferrable loads that may be deferred by the consumer or by radio control from a central computer system (ripple control). Heat may be stored conveniently in several forms on a daily basis. Electric storage heaters that use power only at night may be a key factor in

controlling winter peak loads. At present, there is a lack of cold air storage for air-conditioning systems that may be the single most important electrical load problem facing summer peaking utilities.

Time-of-day pricing would be an effective method of inducing consumers activities to off peak hours. France has successfully implemented a dual day-night pricing system. Several U.S. utilities have instituted time-of-day pricing to encourage off peak energy use and nighttime energy storage.

The Vermont Public Service Board has completed a computer analysis of the State's load to the 1980's assuming various degrees of load management. In 10 years, 10 to 20 percent capacity savings could result with the implementation of load management techniques currently proven feasible. This study also concludes that capital costs to control one kilowatt hour of peak load are \$80 to \$110 versus \$100 to \$300 per kilowatt for peaking capacity.[1/]

With the implementation of load management techniques, oil and gas-fired peaking capacity can be retired and stronger commitments to base loaded coal, nuclear, and hydro could be made. System reserve requirements may be reduced, depending on the diversity of the system generation mix and degree of interconnection.

Projections of load factors made in this study are based on the expected energy and peak demands as presented in the NERC projections. Load management techniques do not attempt to alter total energy consumption, but simply redistributes energy under the load curve to make better use of generating facilities. However, some load management measures decrease energy consumption while other techniques increase use. The net effect of load management on total energy use is, therefore, undetermined.

Nuclear Generation

Following the Three Mile Island accident, political and regulatory uncertainties affecting the future construction of nuclear plants have intensified. As a result, there were no domestic orders in 1979 for nuclear plants, and design and construction has been deferred or cancelled for several nuclear plants. However, despite the debate over

1/ Gilbert, William A., and Degrasse, Richard V., "Prospects for Electric Utility Load Management", Public Utilities Fortnightly August 28, 1975.

nuclear energy, there was about 54,600 megawatts of installed nuclear capacity operating in the United States as of January, 1980. In 1979, nuclear energy accounted for about 11% of the electricity consumed in the United States and as much as 30% in some regions of the county.

Because of the higher than expected investment costs, long lead times, and intensified public concern, new nuclear power generation is not as advantageous today as was expected 10 years ago. However, at the same time, the cost of fuel oil has increased dramatically and may continue to increase far beyond everyone's expectations. Federal and state regulations concerning environmental protection and air pollution have considerably increased the investment, and operation and maintenance costs of coal-fired plants. The changing economic and environmental parameters related to alternative generation make it difficult to forecast future nuclear capacity additions.

The generation mix percentage ranges presented in this volume reflect these uncertainties. In an extreme case, more public opposition to nuclear power could lead to a further slow down of construction of nuclear reactors. Since the development of coal-fired plants also is subject to environmental constraints, fuel delivery, and other delaying factors, opposition to nuclear power could result in a shortage of base load generation. A secondary effect, that might develop slowly, could be increased emphasis on developing hydropower and other renewable resources.

Technological Advancements

Electrical energy demand will also be affected by implementation of various technological changes involving energy source substitutions. One notable example is the electric vehicles.

Recent news articles estimate that there could be 10 to 15 million electric vehicles on the roads by the year 2000. The predictions estimated 100,000 and 7 million units by 1985 and 1990, respectively.[a/] The introduction of electric vehicles will reduce the direct utilization for petroleum and increase the demand for electricity. The total reduction in petroleum utilization will depend on the future electricity generation mix (e.g. with coal and nuclear power supplanting oil in the generation of electricity).

a/ Electrical World, January 1, 1980, page 14.

The potential regional impact of vehicle electrification may be estimated by comparing energy consumption of electric utilities with that consumed by highway gasoline by state for the year 1977 as shown on Table C-11. For example, with 10 percent of the total 1977 highway gasoline use converted to electric energy the total 1977 utility sales would have increased by approximately 20 percent. On a regional basis, the increase in utility sales would range from 11 to 33 percent. The increased electric-energy load on the utilities would be largely off peak.

Other technological changes could lead to an increase in the demand for electricity. For example, in regions of the country with mild winters (non winter peak season) electric heat pumps can be substituted for existing gas-fired units in both residential and industrial uses.

The total future demand for electricity, therefore, will be influenced by the offsetting trends attributed to conservation in end uses versus increased substitution of electricity for existing oil and gas sources of energy.

Conclusion

Conservation measures outlined in this chapter indicate that electricity consumption may be reduced considerably from usage levels existing under a "no conservation" base case[a/] condition. Results show that the range of potential average savings[b/] by consumer category would be as follows:

Residential	22 to 32 percent
Commercial	25 to 45 percent
Industrial	20 to 30 percent

Technological advances show potential for increasing electricity consumption by substituting electricity for oil and gas in direct end uses.

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a/ The base case or "no conservation" condition may be considered conditions existing before the full impact of the October 1973 oil embargo was felt, roughly the period ending in 1976.

b/ Saving in the year 2000 from the base case projection assuming substantial market penetration.

Table C-11

ENERGY CONSUMPTION BY ELECTRIC UTILITIES AND HIGHWAY GASOLINE, BY STATE, 1977

Area	Electricity Consumption[a]/[c]/	Highway[b]/ Gasoline	Total Utility Sales If Increased By 10% of Highway Gasoline	Percentage Increase in Total Utility Sales
	Trillion BTU (1977)			
WSCC - NWPP				
Oregon	119.0	164.7	135.5	14
Washington	219.1	235.0	242.6	11
Idaho	47.7	60.4	53.7	13
Utah	30.3	84.7	38.5	27
Montana	34.2	53.9	39.6	16
WSCC-RMPA				
Wyoming	18.2	39.1	22.1	21
Colorado	62.1	175.5	79.7	28
WSCC-ARA-NM				
Arizona	77.5	158.5	93.4	20
New Mexico	28.2	93.9	37.6	33
WSCC-No. Cal.-Nev.				
California	531.3	1,384.6	669.8	26
Nevada	27.2	54.8	32.7	20
WSCC-So. Cal.-Nev.				
California	531.3	1,384.6	669.8	26
MARCA				
North Dakota	15.2	44.3	19.6	29
South Dakota	14.7	51.7	19.9	35
Nebraska	44.0	105.8	54.6	24
Iowa	77.4	198.2	97.2	26
Minnesota	98.1	250.8	123.2	26

Source: Federal Energy Data System Statistical Summary Update, U.S. Dept. of Energy, July 1979

a/ Table 2: Electric Utility Energy Consumption and Sales.

b/ Table 6: Transporation Energy Consumption.

c/ Electricity Consumption based on Utility Electricity Production for for Sales. This amount does not include generation by private industry or agencies that is not sold to others.

Table C-11 (Continued)

Area	Electricity Consumption[a]/[c]/	Highway[b]/ Gasoline	Total Utility Sales If Increased By 10% of Highway Gasoline	Percentage Increase in Total Utility Sales
	Trillion BTU (1977)			
SWPP				
Oklahoma	91.8	217.4	113.5	24
Arkansas	68.2	156.1	83.8	23
Louisiana	172.6	250.8	197.7	15
Kansas	69.1	162.2	85.3	23
Mississippi	76.5	159.4	92.4	21
ERCOT				
Texas	518.8	1,017.2	620.5	20
SERC-Southern				
Alabama	167.9	255.7	193.5	15
Georgia	162.5	367.7	199.3	23
SERC-Florida				
Florida	268.6	560.6	324.7	21
SERC-TVA				
Tennessee	250.8	300.5	280.9	12
SERC-VACAR				
D.C.	21.9	27.2	24.6	12
Virginia	150.8	335.8	184.4	22
North Carolina	196.6	375.3	234.1	19
South Carolina	117.3	199.1	137.2	17
MAAC				
Pennsylvania	327.5	623.6	389.9	19
New Jersey	158.3	404.7	198.8	26
Delaware	18.7	38.3	22.5	20
Maryland	107.4	246.5	132.0	23

Table C-11 (Continued)

Area	Electricity Consumption[a]/[c]/	Highway[b]/ Gasoline	Total Utility Sales If Increased By 10% of Highway Gasoline	Percentage Increase in Total Utility Sales
		Trillion BTU (1977)		
NPCC-NYPP				
New York	346.5	725.5	419.1	21
NPCC-NEPOOL				
Maine	24.9	70.4	31.9	28
New Hampshire	18.6	54.0	24.0	29
Vermont	11.3	31.8	14.5	28
Rhode Island	16.5	47.8	21.3	29
Connecticut	68.7	172.7	86.0	25
Massachusetts	107.0	299.2	136.9	28
MAIN-Ill.-Mo.				
Missouri	125.2	337.6	159.0	27
Illinois				
MAIN-CECO				
Illinois	317.6	632.6	380.9	20
MAIN-WUMS				
Wisconsin	116.8	278.6	144.7	24
ECAR-Ky.-Ind.				
Kentucky	184.9	229.6	207.9	12
Indiana	185.8	349.4	220.7	19
ECAR-MECS				
Michigan	238.3	588.8	297.2	25
ECAR-AEP				
West Virginia	65.1	111.4	76.2	17
Ohio	411.8	654.0	478.4	16
ECAR-APS				
West Virginia	65.1	111.4	76.2	17

Table C-11 (Continued)

Area	Electricity Consumption[a]/[c]/	Highway[b]/ Gasoline	Total Utility Sales If Increased By 10% of Highway Gasoline	Percentage Increase in Total Utility Sales
	Trillion BTU (1977)			
ECAR-CCD				
Ohio	411.8	654.0	478.4	16
ECAR-CAPCO				
Ohio	411.8	654.0	478.4	16
Alaska	8.4	21.7	10.6	26
Hawaii	19.8	38.2	23.6	19
United States	6,656.3	19,514.8	8,608.0	29

Recent forecasts by the utilities and special study groups incorporate the impact of many conservation measures. Most recent (1979) utility-based forecasts show a significant decrease in projections of future electricity demand when compared to the forecasts made before conservation became important.[a/] It is obvious that evolving economic and political conditions will have major effects on future demands.

We consider that the forecasts in this study are consistent with the composite effect of the many underlying factors influencing the future demand for electricity.

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a/ See Chapter I for the comparison of the latest utility-base forecasts (1979) with the forecasts made in 1976. The reductions in peak demand projection for the year 1995 are consistent with the consumption savings described in this appendix.

APPENDIX C

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